Guideline for Greenhouse Gas Emissions Reporting

(as set out under Ontario Regulation 452/09 under the Environmental Protection Act)

Ontario Ministry of the Environment
December 2010

(Note: This version of the Guideline supersedes the version of the Guideline dated December 2009 (PIBS# 7308e)**)**

Ontario

This Guideline is made in English only

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1. Introduction

Section 4(1) of O.Reg. 452/09 - *Greenhouse Gas Emissions Reporting* ("the Regulation") requires the use of standard quantification methods for quantification of greenhouse gas emissions from each of the sources specified in Section 2 of the Regulation. These standard quantification methods are set out in Section 4 of this Guideline. Some of the standard quantification methods in this Guideline provide two or more options for calculation, sampling, analysis and measurement procedures depending on the type of fuels and other material used in industrial processes.

Section 4(6)(a) of the Regulation also provides for the use of best alternative quantification methods for reports submitted in 2011 on 2010 GHG emissions. Section 3 of the Guideline sets out these best alternative quantification methods.

Section 5 of the Guideline provides a listing of the technical reference documents referred to within the standard quantification methods.

This Guideline dated December 2010 supersedes the version of the Guideline dated December 2009.

2. Definitions

For the purposes of this Guideline:

"**Associated gas**" means a natural gas which is found in association with crude oil, either dissolved in crude oil or as a cap of free gas above the crude oil.

"**Barrel**" ("**bbl**") means a volume equal to 42 U.S. gallons.

"**Biogenic emissions**" means the emissions from the combustion of biomass.

"**Bottoming cycle plant**" means a cogeneration plant in which the energy input to the system is first applied to a useful thermal energy application or process, and at least some of the reject heat emerging from the application or process is then used for electricity production.

"**Calcination**" means the thermal decomposition of carbonate-based minerals, into one or more oxides and carbon dioxide

"**Calcine**" means to heat a substance to a high temperature but below its melting or fusion point causing oxidation or reduction.

"**Calcined byproduct/waste type**" means lime kiln dust and other partially calcined materials and co-products generated during the production of quicklime.

"**CAS number**" means the Chemical Abstracts Service Registry number.

"**Catalytic cracking**" means the process of breaking down larger, heavier, and more complex hydrocarbon molecules into simpler and lighter molecules through the use of a catalyst.

"**Catalytic reforming**" means the process of using controlled heat and pressure with catalysts to rearrange certain hydrocarbon molecules.

"**Cement kiln dust**" ("**CKD**") means the fine-grained, solid, highly alkaline waste removed from cement kiln exhaust gas by air pollution control devices, consisting of partly calcined kiln feed material, dust from cement kilns and bypass systems, including bottom ash and bypass dust.

"**Clinker**" means the mass of fused material produced in a cement kiln from which finished cement is manufactured by milling and grinding.

"**Cogeneration unit**" means a stationary fuel combustion device which simultaneously generates multiple forms of useful energy (usually electrical and thermal) that is (i) used by the person where the cogeneration unit is located; or (ii) transferred to another facility for use by that facility.

"**Cogeneration system**" means individual cogeneration components including the prime mover (heat engine), generator, heat recovery, and electrical interconnection, configured into an integrated system that provides sequential generation of multiple forms of useful energy (usually electrical and thermal), at least one form of which the facility consumes on-site or makes available to other users for an end-use other than electricity generation.

"**Coke** " means a solid residue consisting mainly of carbon which is derived either from the cracking of petroleum hydrocarbons in a refinery coker unit (petroleum coke) or from the destructive distillation of low-ash, low-sulphur bituminous coal (coal coke).

"**Coke burn-off**" means the removal of coke from the surface of a catalyst through combustion during catalyst regeneration.

"**Combustion emissions**" means greenhouse gas emissions occurring during the exothermic reaction of a fuel with oxygen.

"**Continuous emissions monitoring system (CEMS)**" means the total equipment required to obtain a continuous measurement of a gas concentration or emission rate from combustion or industrial processes.

"**Director**" means a Director appointed by the Minister for Section 4 of O.Reg 452/09.

"**Distillate fuel oil**" means fuels oils No. 1, 2 and 4 and diesel fuel. "dSm^3" means dry standard cubic metre – the amount of gas that would occupy a volume of one cubic metre if free of combined water at standard conditions.

"**Electricity generating unit**" ("**EGU**") is any combustion device that combusts solid, liquid, or gaseous fuel for the purpose of producing electricity either for sale or for use onsite. This source includes cogeneration (combined heat and power) units. This source does not include portable or emergency generators less than 10 MW in nameplate generating capacity as defined in the Guideline.

"**Emergency generator**" means a stationary combustion device, such as a reciprocating internal combustion engine or turbine that serves solely as a secondary source of mechanical or electrical power whenever the primary energy supply is disrupted or discontinued during power outages or natural disasters that are beyond the control of the person of a facility. An emergency generator operates only during emergency situations, for training of personnel under simulated emergency conditions, as part of emergency demand response procedures, or for standard performance testing procedures as required by law or by the generator manufacturer. A generator that serves as a back-up power source under conditions of load shedding, peak shaving, power interruptions pursuant to an interruptible power service agreement, or scheduled facility maintenance shall not be considered an emergency generator.

"**Emergency equipment**" means any auxiliary fossil fuel-powered equipment, such as a fire pump, that is used only in emergency situations.

"**Emission factors**" ("**EF**") means the rate at which a pollutant is released into the atmosphere (or captured) as a result of some process activity or unit throughput. The EFs used may be average or general EFs, or technology-specific EFs.

"**Engineering estimates**" means estimating emissions from engineering principles and judgment, using knowledge of the chemical and physical processes involved, the design features of the source, and an understanding of the applicable physical and chemical laws.

"**Equipment leak**" means fugitive greenhouse gas emissions from equipment including valves, pump seals, flanges, compressors, sampling connections, and open-ended lines and excluding storage tank emissions.

"**Flexigas**" means a low heat content gaseous fuel produced through the gasification of coke.

"**Fluid catalytic cracking unit**" ("**FCCU**") means a process unit in a refinery in which crude oil or a crude oil-derived feedstock is charged and fractured into smaller molecules in the presence of a catalyst, or reacts with a contact material to improve feedstock quality for additional processing, and in which the catalyst or contact material is regenerated by burning off coke and other deposits. The unit includes, but is not limited to, the riser, reactor, regenerator, air blowers, spent catalyst, and all equipment for controlling air pollutant emissions and recovering heat.

"**Fluid coking**" means a thermal cracking process utilizing the fluidized-solids technique to remove carbon (coke) for continuous conversion of heavy, low-grade oils into lighter products.

"**Fuel analytical data**" means any data collected about the mass, volume, flow rate, heat content, or carbon content of a fuel.

"**Fuel gas system**" means a system of compressors, piping, knock-out pots, mix drums, sulphur removal units and flaring units that collects fuel gas from one or more sources for treatment, and transports it to a stationary combustion unit.

"**General stationary combustion**" means the combustion of solid, liquid or gaseous fuel for the purposes of producing electricity, generating steam or providing useful heat or energy for industrial, commercial, or institutional use; or providing energy for pollution control; or reducing the volume of waste by removing combustible matter.

"**GJ**" means gigajoules or billion joules.

"**High heat value**" ("**HHV**") means the amount of heat energy released by the combustion of a unit quantity of a fuel, including the latent heat of vaporization of water embedded in the fuel.

"**Hydrogen plant**" means a plant that produces hydrogen with steam hydrocarbon reforming, partial oxidation of hydrocarbons, or other processes.

"**Kiln**" means thermally insulated chambers, or ovens, in which controlled temperature regimes are produced, used in the production of clinker, lime and other products, and which includes any associated preheater or precalciner devices.

"**Lime kiln dust**" ("**LKD**") means lime dust produced in the course of production of quick lime.

"**Lime type**" means three types of quicklime derived from limestone containing varying percentages of magnesium carbonate. The three lime types are:
 a) High calcium quicklime, which is derived from limestone containing 0 to 5 per cent magnesium carbonate.
 b) Magnesium quicklime, which is derived from limestone containing 5 to 35 per cent magnesium carbonate.
 c) Dolomitic quicklime, which is derived from limestone containing 35 to 46 per cent magnesium carbonate.

"**Liquefied petroleum gas**" (**LPG**) means a group of gaseous hydrocarbons derived from crude oil refining or natural gas fractionation, and includes propane, propylene, normal butane, butane, butylene, isobutene and isobutylene.

"**Load shedding**" means the process engaged in by power system operators whereby the power load of pre-selected customers is deliberately removed from a power system in response to an abnormal condition in order to maintain the integrity of the system and minimize customer outages.

"**Low heat content gas**" means gases recovered from casing vents, vapor recovery systems, storage tanks and other components within the production process of crude oil, natural gas and petroleum products.

"**Low Heat Value**" ("**LHV**") means the heat energy released through the combustion of a unit quantity of fuel, excluding the latent heat of vaporization of water embedded in the fuel.

"**Mass balance**" means the application of the law of conservation of mass to a facility, process or piece of equipment to determine emissions based on the difference in the input and output of a unit operation, where the accumulation and depletion of a substance are included in the calculations.

"**Measurement uncertainty**" means the scientific uncertainty associated with measuring of GHG emissions due to limitations of monitoring equipment or quantification methodologies.

"**MJ**" means mega joules or one million joules.

"Nameplate generating capacity" means the maximum rated electrical power output of a generator under specific conditions designated by the manufacturer, expressed in megawatts (MW) or kilowatts (kW).

"**Net power generated**" means the gross electricity generation minus station service or unit service electricity requirements, expressed in megawatt hours (MWh) per year. In the case of cogeneration, this value includes internal consumption of electricity for the purposes of a production process, as well as including power put on the grid.

"**Non-calcined calcium oxide**" means calcium oxide that remains in the clinker or CKD in the form of $CaCO_3$ and calcium oxide in the clinker or CKD that entered the kiln as a non-carbonate species.

"**Non-calcined magnesium oxide**" means magnesium oxide that remains in the clinker or CKD in the form of $MgCO_3$ and magnesium oxide in the clinker or CKD that entered the kiln as a non-carbonate species.

"**Peak shaving**" means using on-site generation intermittently to avoid purchasing grid electricity during expensive peak-rates or using on-site generation during periods of maximum electricity consumption expressly with the intention of lowering the energy demand component of a given billing period.

"**Person**" means the person mentioned in Section 2 of the Regulation.

"**Pipeline quality natural gas**" means natural gas having a high heat value equal to or greater than 36.3 MJ/m3 or less than 40.98 MJ/m3, and which is at least ninety per cent methane by volume, and which is less than five per cent carbon dioxide by volume.

"**Portable**" means designed and capable of being carried or moved from one location to another. Indications of portability include but are not limited to wheels, skids, carrying handles, dolly, trailer, or platform. Equipment is not portable if any one of the following conditions exists:
   a) The equipment is attached to a foundation.
   b) The equipment or a replacement resides at the same location for more than 12 consecutive months.
   c) The equipment is located at a seasonal facility and operates during the full annual operating period of the seasonal facility, remains at the facility for at least two years, and operates at that facility for at least three months each year.
   d) The equipment is moved from one location to another in an attempt to circumvent the portable residence time requirements of this definition.

"**Prime mover**" means the type of equipment such as an engine or water wheel that drives an electric generator. "Prime movers" include, but are not limited to, reciprocating engines, combustion or gas turbines, steam turbines, microturbines, and fuel cells.

"**Process**" means the intentional or unintentional reactions between substances or their transformation, including, but not limited to, the chemical or electrolytic reduction of metal ores, the thermal decomposition of substances, and the formation of substances for use as product or feedstock.

"**Process emissions**" means the emissions from industrial processes (e.g., cement production, ammonia production) involving chemical or physical transformations other than fuel combustion. For example, the calcination of carbonates in a kiln during cement production or the oxidation of methane in an ammonia process results in the release of process CO_2 emissions to the atmosphere and thus would be process emissions. Emissions from fuel combustion to provide process heat are not part of process emissions, whether the combustion is internal or external to the process equipment.

"**Process vent**" means an opening where a gas stream is continuously or periodically discharged during normal operation.

"**Purge gas**" means nitrogen, carbon dioxide, liquefied petroleum gas, or natural gas used to maintain a non-explosive mixture of gases in a flare header or used to provide sufficient exit velocity to prevent regressive flame travel back into the flare header.

"**Quicklime**" means a substance that consists of oxides of calcium and magnesium resulting from the calcination of limestone or other highly calcareous materials such as aragonite, chalk, coral, marble and shell.

"**Refinery fuel gas**" means gas generated at a petroleum refinery or any gas generated by a refinery process unit, and that is combusted separately or in any combination with any type of gas or used as a chemical feedstock.

"**Rm^3**" means reference cubic metre - the amount of gas that would occupy a volume of one cubic metre under reference temperature and pressure conditions.

"**Sinter production**" means a process that produces a fused aggregate of fine iron-bearing materials suited for use in a blast furnace. The sinter machine is composed of a continuous traveling grate that conveys a bed of ore fines and other finely divided iron-bearing material and fuel (typically coke breeze), a burner at the feed end of the grate for ignition, and a series of downdraft windboxes along the length of the strand to support downdraft combustion and heat sufficient to produce a fused sinter product.

"**Standard conditions**"" means either a temperature of 15 degrees Celsius and a pressure of 101.325 kPa. unless otherwise stated in the Standard Quantification Methods (Section 4) or the Technical Reference Documents (section 5).

"**Standard Temperature and Pressure**" has the same meaning as standard conditions.

"**STP**" means Standard Temperate and Pressure.

"**Sm^3**" means standard cubic metre - the amount of gas that would occupy a volume of one cubic metre under standard conditions.

"**Steam reforming**" means the process by which methane and other hydrocarbons in natural gas are converted into hydrogen and carbon monoxide by reaction with steam over a catalyst.

"**Still gas**" has the same meaning as "Refinery Fuel Gas"

"**Sulphur recovery unit**" ("**SRU**") means a process unit that recovers elemental sulphur from gases that contain reduced sulphur compounds and other pollutants, usually by a vapor-phase catalytic reaction of sulphur dioxide and hydrogen sulfide.

"**Supplemental firing**" means an energy input to the cogeneration facility used only in the thermal process of a topping cycle plant, or in the electricity generating or manufacturing process of a bottoming cycle plant.

"**Topping cycle plant**" means a cogeneration plant in which the energy input to the plant is first used to produce electricity, and at least some of the reject heat from the electricity production process is then used to provide useful thermal output.

"**Unstabilized crude oil**" means crude oil that is pumped from the well to a pipeline or pressurized storage vessel for transport to the refinery without intermediate storage in a storage tank at atmospheric pressures. Unstabilized crude oil is characterized by having a true vapor pressure of 5 pounds per square inch absolute (psia) or greater.

"**Useful thermal output**" means the thermal energy made available in a cogeneration system for use in any industrial or commercial process, heating or cooling application, or delivered to other end users, i.e., total thermal energy made available for processes and applications other than electrical generation.

"**Waste derived fuel**" has the same meaning as in Regulation 347 of the Revised Regulations of Ontario (General – Waste Management).

"**Wastewater separator**" means equipment used to separate oils and water from locations downstream of process drains.

3. Best Alternative Quantification Methods

Section 4(6) of the Regulation provides for the use of best alternative quantification methods if the person mentioned in subsection 2 of the Regulation is unable during 2010 to quantify CO_2e generated from a source using the applicable standard quantification method . This section of the Guideline specifies the alternative quantification methods.

Best alternative quantification methods are any of the published methods included in the following list:

Best Alternative Quantification Method	Link
1. U.S. EPA, 40 CFR Part 98, Mandatory Greenhouse Gas Reporting, Subparts A to Subpart PP	http://www.epa.gov/climatechange/emissions/downloads09/GHG-MRR-Full%20Version.pdf
2. 2006 IPCC Guidelines for National Greenhouse Gas Inventories - Volume 3 -Industrial Processes and Product Use	http://www.ipcc-nggip.iges.or.jp/public/2006gl/vol3.html
3. Environment Canada, Sector Specific Protocols and Guidance Manuals, posted on the Environment Canada website	http://www.ec.gc.ca/pdb/ghg/guidance/calcu_pro_e.cfm
4. CO_2 Emissions Calculation Protocol for the Lime Industry—English Units Version, February 5, 2008 Revision—National Lime Association	Available for purchase from the National Lime Association (NLA), 200 North Glebe Road, Suite 800, Arlington, Virginia 22203, (703) 243-5463, http://www.lime.org
5. Methodology Manual – Estimation of Air Emissions from the Canadian Natural Gas Transmission, Storage and Distribution System, Prepared for Canadian Energy Partnership for Environmental Innovation (CEPEI), by Clearstone Engineering, September 25, 2007	Available from Ministry of the Environment
6. American Petroleum Institute (API) Compendium of GHG Emission Methodology for the Oil and Gas Industry, August 2009	http://www.api.org/ehs/climate/new/upload/2009_GHG_COMPENDIUM.pdf
7. CO_2 Accounting and Reporting Standard for the Cement Industry, June 2005, Version 2.0, World Business Council for Sustainable Development	http://www.wbcsd.org/web/publications/cement-tf1.pdf

Best Alternative Quantification Method	Link
8. Calculation tools for Estimating Greenhouse Gas Emissions from Pulp and Paper Mills – Version 1.1, ICFPA/NCASI	http://www.ncasi.org/programs/areas/climate/ghgtools/pulp_icfpa.aspx

If the person is unable to use any of the best alternative quantification methods set out above, section 4(6)(b) of the Regulation stipulates that a person may apply to the Director for written consent to use a method other than the standard quantification methods or the best alternative quantification methods.

4. Standard Quantification Methods

Section 4(1) paragraph 1 of the Regulation specifies the need to quantify greenhouse gases using a standard quantification method that is set out for each source in the Guideline. This section sets out the standard quantification methods that are to be used. Copies of the methods are provided in the appendices.

Source of Greenhouse Gas	Standard Quantification Method	Appendix
Adipic acid manufacturing	ON.50	1
Primary manufacturing aluminum	ON.70	2
Ammonia manufacturing	ON.80	3
Carbonate use	ON.180	4
Cement manufacturing	ON.90	5
Coal storage	ON.100	6
Copper production	ON.260	7
Electricity generation and cogeneration	ON.40	8
Ferroalloy production	ON.270	9
General stationary combustion	ON.20	10
Glass production	ON.140	11
HCFC-22 production and HFC-23 destruction	ON.120	12
Hydrogen production	ON.130	13

Source of Greenhouse Gas	Standard Quantification Method	Appendix
Iron manufacturing	ON.150	14
Lead production	ON.160	15
Lime manufacturing	ON.170	16
Nickel production	ON.260	17
Nitric acid manufacturing	ON.310	18
Petrochemical production	ON.300	19
Petroleum refining	ON.200	20 and 20a
Phosphoric acid production	ON.340	21
Pulp and paper manufacturing	ON.210	22
Refinery fuel gas use within a petroleum refinery	ON.30	23
Soda ash manufacturing	ON.220	24
Steel manufacturing	ON.150	25
Zinc production	ON.240	26

<u>Provision for Liquid Fuel and Gas Flow Meters Calibrating Postponement</u>

In units and processes that operate continuously with infrequent outages, the initial calibration of flow meters or other devices may be postponed until the next scheduled maintenance shutdown. If a person intends to postpone the calibration of flow meters or other devices until the next scheduled maintenance shutdown, the person shall prepare a plan documenting any postponements from the dates that the standard quantification methods require the flow meters to be in place and shall submit the plan to the Director by June 1, 2011. The plan shall also include the date for the next planned shutdown.

5. Technical Reference Documents

All of the documents listed in the "Reference Title" column of the following table are incorporated into the Guideline as amended from time to time and where the Guideline requires the use of one of these methods, the most current version shall be used. Where the analysis or other measurements specified by the methods in the "Reference Title" column or in any of the methods in the Appendices are not offered by any supplier in Ontario, the Person may request approval by the Director in writing for another equivalent method.

Reference Title	Website
Analytical Methods section of the National Lime Association 'CO$_2$ Emissions Calculation Protocol for the Lime Industry English Units Version', February 5, 2008	http://www.climatevision.gov/sectors/lime/protocols.html
ASM CS-104 UNS No. G10460 "Carbon Steel of Medium Carbon Content".	http://www.asme.org/Codes/Publications/
ASME Performance Test Codes	http://www.asme.org/Codes/Publications/
ASTM C25 - Standard Test Method for Chemical Analysis of Limestone, quicklime, and Hydrated Lime	http://www.astm.org/Standard/index.shtml
ASTM C114 - Standard Test Methods for Chemical Analysis of Hydraulic Cement	http://www.astm.org/Standard/index.shtml
ASTM D240 - Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimetre	http://www.astm.org/Standard/index.shtml
ASTM D1298 - Standard Test Method for Density, Relative Density (Specific Gravity)	http://www.astm.org/Standard/index.shtml
ASTM D1826 - Standard Test Method for Calorific (Heating) Value of Gases in Natural Gas Range by Continuous Recording Calorimetre	http://www.astm.org/Standard/index.shtml
ASTM D1945 - Standard Test Method for Analysis of Natural Gas by Gas Chromatography	http://www.astm.org/Standard/index.shtml
ASTM D1946 - Standard Practice for Analysis of Reformed Gas by Gas Chromatography	http://www.astm.org/Standard/index.shtml
ASTM D2013 - Standard Practice of Preparing Coal Samples for Analysis.	http://www.astm.org/Standard/index.shtml
ASTM D2234/D2234M - Standard Practice for Collection of a Gross Sample of Coal.	http://www.astm.org/Standard/index.shtml
ASTM D2502 - Standard Test Method for Estimation of Molecular Weight (Relative Molecular Mass) of Petroleum Oils from Viscosity Measurements	http://www.astm.org/Standard/index.shtml

Reference Title	Website
ASTM D2503 - Standard Test Method for Relative Molecular Mass (Relative Molecular Weight) of Hydrocarbons by Thermoelectric Measurement of Vapor Pressure	http://www.astm.org/Standard/index.shtml
ASTM D2597 - Standard Test Method for Analysis of Demethanized Hydrocarbon Liquid Mixtures Containing Nitrogen and Carbon Dioxide by Gas Chromatography.	http://www.astm.org/Standard/index.shtml
ASTM D3176 - Standard Practice for Ultimate Analysis of Coal and Coke.	http://www.astm.org/Standard/index.shtml
ASTM D3238 - Standard Test Method for Calculation of Carbon Distribution and Structural Group Analysis of Petroleum Oils by the n-d-M Method	http://www.astm.org/Standard/index.shtml
ASTM D3588 - Standard Practice for Calculating Heat Value, Compressibility Factor, and Relative Density of Gaseous Fuels	http://www.astm.org/Standard/index.shtml
ASTM D3682 - Standard Test Method for Major and Minor Elements in Combustion Residues from Coal Utilization Processes.	http://www.astm.org/Standard/index.shtml
ASTM D4057 - Standard Practice for Manual Sampling of Petroleum and Petroleum Products	http://www.astm.org/Standard/index.shtml
ASTM D4177 - Standard Practice for Automatic Sampling of Petroleum and Petroleum Products.	http://www.astm.org/Standard/index.shtml
ASTM D4809 - Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter (Precision Method)	http://www.astm.org/Standard/index.shtml
ASTM D4891 - Standard Test Method for Heating Value of Gases in Natural Gas Range by Stoichiometric Combustion	http://www.astm.org/Standard/index.shtml
ASTM D5142 - Standard Test Methods for Proximate Analysis of the Analysis Sample of Coal and Coke by Instrumental Procedures, for petroleum liquid based fuels and liquid waste-derived fuels	http://www.astm.org/Standard/index.shtml
ASTM D5291 - Standard Test Methods for Instrumental Determination of Carbon,	http://www.astm.org/Standard/index.shtml

Reference Title	Website
Hydrogen, and Nitrogen in Petroleum Products and Lubricants	
ASTM D5373 - Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal and Coke	http://www.astm.org/Standard/index.shtml
ASTM D5468 - Standard Test Method for Gross Calorific and Ash Value of Waste Materials	http://www.astm.org/Standard/index.shtml
ASTM D5865 - Standard Test Method for Gross Calorific Value of Coal and Coke	http://www.astm.org/Standard/index.shtml
ASTM D6348 - Standard Test Method for Determination of Gaseous Compounds by Extractive Direct Interface Fourier Transform Infrared (FTIR) Spectroscopy	http://www.astm.org/Standard/index.shtml
ASTM D6609 - Standard Guide for Part-Stream Sampling of Coal.	http://www.astm.org/Standard/index.shtml
ASTM D6866 - Standard Test Methods for Determining the Biobased Content of Solid, Liquid, and Gaseous Samples Using Radiocarbon Analysis	http://www.astm.org/Standard/index.shtml
ASTM D6883 - Standard Practice for Manual Sampling of Stationary Coal from Railroad Cars, Barges, Trucks, or Stockpiles	http://www.astm.org/Standard/index.shtml
ASTM D7430 - Standard Practice for Mechanical Sampling of Coal	http://www.astm.org/Standard/index.shtml
ASTM D7459 - Standard Practice for Collection of Integrated Samples for the Speciation of Biomass (Biogenic) and Fossil-Derived Carbon Dioxide Emitted from Stationary Emissions Sources	http://www.astm.org/Standard/index.shtml
ASTM D7633 - 10 Standard Test Method for Carbon Black Carbon Content	http://www.astm.org/Standard/index.shtml
ASTM D7662 - 10 - Standard Test Method for Carbon Content in Carbon Black Feedstock Oils	http://www.astm.org/Standard/index.shtml
ASTM E415 - Standard Test Method for Atomic	http://www.astm.org/Standard/ind

Reference Title	Website
Emission Vacuum Spectrometric Analysis of Carbon and Low-Alloy Steel	ex.shtml
ASTM E1019 - Standard Test Methods for Determination of Carbon, Sulfur, Nitrogen, and Oxygen in Steel, Iron, Nickel, and Cobalt Alloys by Various Combustion and Fusion Techniques	http://www.astm.org/Standard/index.shtml
ASTM E1915 - Standard Test Methods for Analysis of Metal Bearing Ores and Related Materials by Combustion Infrared-Absorption Spectrometry	http://www.astm.org/Standard/index.shtml
ASTM E1941 - Standard Test Method for Determination of Carbon in Refractory and Reactive Metals and Their Alloys	http://www.astm.org/Standard/index.shtml
ASTM UOP539 - Refinery Gas Analysis by Gas Chromatography	http://www.astm.org/Standard/index.shtml
CCME EPC-73E: Environmental Code of Practice for the Measurement and Control of Fugitive VOC Emissions from Equipment Leaks (1993)	http://www.ccme.ca/assets/pdf/pn_1106_e.pdf
Environment Canada "Protocols and Performance specifications for Continuous Monitoring of Gaseous Emissions from Thermal Power Generation - Report EPS 1/PG/7 dated December 2005	Available from Ministry of the Environment
Gas Processors Association (GPA) 2261–00, Revised 2000 - Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography.	http://www.techstreet.com/cgi-bin/detail?product_id=861546 http://infostore.saiglobal.com/store/Portal.aspx?publisher=GPA
Gas Processors Association (GPA) 2172:1996, Calculation of Gross Heating Value, Relative Density and Compressibility For Natural Gas Mixtures From Compositional Analysis	http://infostore.saiglobal.com/store/Portal.aspx?publisher=GPA
ISO/TR 15349-1: 1998 - Unalloyed steel – Determination of low carbon content, Part 1: Infrared absorption method after combustion in an electric resistance furnace (by peak separation) (1998-10-15) – First Edition	http://www.iso.org/iso/catalogue_detail.htm?csnumber=27521
ISO/TR 15349-3: 1998 - Unalloyed steel –	http://www.iso.org/iso/catalogue_

Reference Title	Website
Determination of low carbon content, Part 3: Infrared absorption method after combustion in an electric resistance furnace (with preheating) (1998-10-15) – First Edition	detail.htm?csnumber=27523
ISO 3170: Petroleum Liquids— Manual sampling—Third Edition.	http://www.iso.org/iso/catalogue_detail.htm?csnumber=29283
ISO 3171: Petroleum Liquids— Automatic pipeline sampling—Second Edition.	http://www.iso.org/iso/catalogue_detail.htm?csnumber=8357
Technical Association of the Pulp and Paper Industry (TAPPI) T684 om-06 "Gross High Heating Value of Black Liquor"	http://www.tappi.org/Bookstore/Standards--TIPs/Standards/Nonfibrous-Materials/Gross-Heating-Value-of-Black-Liquor-Test-Method-T-684-om-06.aspx
Technical Association of the Pulp and Paper Industry (TAPPI) T650 om-05 "Solids Content of Black Liquor"	http://www.techstreet.com/standards/TAPPI/T650_05?product_id=1221095
U.S. EPA Method 320 (40 CFR part 63, Appendix A)	http://www.epa.gov/ttn/emc/promgate/m-320.pdf
U.S. EPA TANKS Version 4.09D, U.S. Environmental Protection Agency, October 2005	http://www.epa.gov/ttnchie1/software/tanks/index.html#order
U.S. EPA AP 42, Fifth Edition, Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources	http://www.epa.gov/ttn/chief/ap42/index.html

Appendices

ON.50   Adipic Acid Manufacturing

ON.50   Source Definition

The adipic acid production source consists of all adipic acid production facilities that use oxidation to produce adipic acid.

ON.52   Greenhouse Gas Reporting Requirements

For the purpose of Section 6 of the Regulation the annual emissions data report for adipic acid manufacturing shall include the following information at the facility level calculated in accordance with this method:

(a) Annual process N_2O emissions from adipic acid production (tonnes).

(b) Annual adipic acid production (tonnes).

(c) Emissions of CO_2, CH_4, and N_2O from stationary combustion units must also be reported under ON.20 (tonnes).

ON.53   Calculation of N_2O Emissions

(a) The person must determine annual N_2O emissions from adipic acid production according to paragraphs (a)(1) or (a)(2) of this section:

    (1) Use a site-specific emission factor and production data according to paragraphs (b) through (h) of this section.

    (2) Request approval by the Director in writing for another method of determining N_2O emissions.

(b) The person must conduct an annual performance test or use continuous monitors according to paragraphs (b)(1) through (b)(3) of this section.

    (1) The person must either conduct the test on the waste gas stream from the nitric acid oxidation step of the process using the methods specified in ON.54 (b) through (d) or use a continuous monitoring system.

    (2) The person must either conduct the performance test under normal process operating conditions and without using N_2O abatement technology or use a continuous monitoring system.

    (3) The person must either measure the adipic acid production during the test and calculate the production rate for the test period or the continuous monitoring period in tonnes per hour.

(c) The person must determine an N_2O emissions factor to use in Equation 50-2 of this section according to paragraphs (c)(1) or (c)(2) of this section.

    (1) The person may request Director approval in writing for another method of determining N_2O concentration according to the procedures in paragraphs (a)(2) of this section.

(2) Using the results of the test or continuous monitors in paragraph (b) of this section, the person must calculate a facility-specific emissions factor according to Equation 50-1 for performance test and 50-1a for continuous monitors of this section:

$$EF_{N2O} = \frac{\sum_{1}^{n} \dfrac{C_{N2O} * 1.826 \times 10^{-6} * Q}{P}}{n} \qquad \textbf{Equation 50-1}$$

$$EF_{N2O} = \frac{C_{N2O} * 1.826 \times 10^{-6} * Q}{P} \qquad \textbf{Equation 50-1a}$$

Where:

EF_{N2O} = Average facility-specific N_2O emissions factor without using N2O abatement technology (kg N_2O generated/tonne adipic acid produced).

C_{N2O} = average N_2O concentration during the performance test or average hourly concentrations for continuous monitors (ppm N_2O).

1.826×10^{-6} = Conversion factor (kg/dSm^3-ppm N_2O).

Q = average volumetric flow rate of effluent gas per test run during the performance test or average hourly readings for continuous monitor (dSm^3/hr).

P = average production rate during the performance test or the average hourly production rate for continuous monitors during the period (tonnes adipic acid produced/hr).

n = Number of test runs.

(d) If applicable, the person must determine the destruction efficiency for each N_2O abatement technology used at the facility according to paragraphs (d)(1), (d)(2), (d)(3) or (d)(4)of this section.

(1) Use the manufacturer's specified destruction efficiency.

(2) Estimate the destruction efficiency through process knowledge. Examples of information that could constitute process knowledge include calculations based on material balances, process stoichiometry, or previous test results provided the results are still relevant to the current vent stream conditions. The person must document how process knowledge was used to determine the destruction efficiency.

(3) Calculate the destruction efficiency by conducting an additional performance test on the emissions stream following the N_2O abatement technology.

(4) Calculate the destruction efficiency by the use of continuous monitors on the controlled and uncontrolled emissions.

(e) If applicable, the person must determine the abatement factor for each N_2O abatement technology used at the facility. The abatement factor is calculated for each adipic acid facility according to Equation 50-2 of this section.

$$AF = \frac{P_{a\ Abate}}{P_a}$$

Equation 50-2

Where:

AF = Abatement factor of N_2O abatement technology (fraction of production in the testing period that abatement technology is operating).

$P_{a\ Abate}$ = adipic acid production in the testing period during which N_2O abatement was used (tonne acid produced).

P_a = Total adipic acid production in the testing period (tonne acid produced).

(f) The person must determine the annual amount of adipic acid produced and the annual adipic acid production during which N_2O abatement is operating.

(g) The person must calculate annual adipic acid production process emissions of N_2O by multiplying the emissions factor (determined using Equation 50-1 or 50-1a of this section) by the adipic acid production for each period and accounting for N_2O abatement, according to Equation 50-3 of this section:

$$N_2O = \sum_{i=1}^{N} \frac{EF_{N2Oi} * P_{ai} * (1-(DF_i * AF_i))}{1000}$$

Equation 50-3

Where:

N_2O = Annual N_2O mass emissions from adipic acid production (tonnes).

EF_{N2Oi} = Facility-specific N_2O emissions factor for the period without abatement technology (kg N_2O generated/tonne adipic acid produced).

P_{ai} = Adipic acid produced in the period (tonnes).

DF_i = Destruction efficiency of N_2O abatement technology N (abatement device destruction efficiency, per cent of N_2O removed from air stream).

AF_i = Abatement factor of N_2O abatement technology N (fraction of period that is production abatement technology is operating).

1000 = Conversion factor (kg/tonne).

N = Number of different periods in the year. For performance test, the period would be the time between each test (e.g., N is 1 year if

performance test conducted annually). For continuous monitors, N would be the number of months in the year (or more), with P_{ai}, EF_{N2Oi}, DF_i and AF_i to be calculated for each month.

ON.54 Sampling, Analysis, and Measurement Requirements

(a) The person must conduct a new performance test and calculate a new facility-specific emissions factor according to the frequency specified in paragraphs (a)(1) of this section, or use continuous monitors to calculate a facility-specific emissions factor and destruction efficiency according to paragraphs (a)(2) of this section.

(1) Performance Test

(i) Conduct the performance test annually or

(ii) Conduct the performance test when the adipic acid production process is changed either by altering the ratio of cyclohexanone to cyclohexanol or by installing abatement equipment.

(2) Continuous Monitors

(i) Continuous monitors shall be used to determine the uncontrolled emissions and the controlled N_2O emissions to derive an N_2O emission factor and abatement system destruction factor.

(ii) The continuous monitors shall be operated in accordance with quality assurance and quality control programs approved in writing by the Director.

(b) The person must measure the N_2O concentration during the performance test using one of the methods in paragraphs (b)(1) through (b)(3) of this section.

(1) EPA Method 320, Measurement of Vapor Phase Organic and Inorganic Emissions by Extractive Fourier Transform Infrared (FTIR) Spectroscopy in 40 CFR part 63 (U.S.), Appendix A;

(2) ASTM D6348 - Standard Test Method for Determination of Gaseous Compounds by Extractive Direct Interface Fourier Transform Infrared (FTIR) Spectroscopy; or

(3) An equivalent method or continuous monitors, approved in writing by the Director.

(c) The person must determine the production rate(s) during the performance test according to paragraph (c)(1) or (c)(2) of this section.

(1) Direct measurement (such as using flow meters or weigh scales).

(2) Existing plant procedures used for accounting purposes (such as sales records).

(d) The person must conduct all required performance tests according to the methods in ON.54(b). For each test, the facility must prepare an emissions factor determination report that must include the items in paragraphs (d)(1) through (d)(3) of this section:

(1) Analysis of samples, determination of emissions, and raw data.

(2) All information and data used to derive the emissions factor.

(3) The production rate(s) during the performance test and how each production rate was determined.

(e) The person must determine the monthly adipic acid production quantity and the monthly adipic acid production during which N_2O abatement technology is operating according to the methods in paragraphs (c)(1) or (c)(2) of this section.

(f) The person must determine the annual adipic acid production quantity and the annual adipic production quantity during which N_2O abatement technology is operating by summing the respective monthly adipic acid production quantities.

ON.55   Procedures for Estimating Missing Data.

The person is required to retain a complete record of all measured parameters used in the GHG emissions calculations. Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter shall be used in the calculations as specified in paragraphs (a) and (b) of this section.

(a) For each missing value of monthly adipic acid production, the substitute data shall be the best available estimate based on all available process data or data used for accounting purposes (such as sales records).

(b) For missing values related to the performance test, including emission factors, production rate, and N_2O concentration, the person must conduct a new performance test according to the procedures in ON.54 (a) through (d).

ON.70   Primary Aluminum Manufacturing

ON.71   Source Definition

(a) A primary aluminum production facility manufactures primary aluminum using the Hall-Héroult manufacturing process. The primary aluminum manufacturing process comprises the following operations:

(1) Electrolysis in prebake and Søderberg cells.

(2) Anode baking for prebake cells.

(b) This source does not include experimental cells or research and development process units.

ON.72   Greenhouse Gas Reporting Requirements

For the purpose of Section 6 of the Regulation the annual emissions data report for primary aluminum manufacturing shall include the following information at the facility level calculated in accordance with this method:

(a) Perfluoromethane (CF_4), and perfluoroethane (C_2F_6) emissions from anode effects in all prebake and Søderberg electolysis cells (tones).

(b) CO_2 emissions from anode consumption during electrolysis in all prebake and Søderberg electolysis cells (tonnes).

(c) CO_2 emissions from on-site anode baking (tonnes).

(d) Emissions of CO_2, CH_4, and N_2O from stationary combustion units not covered by this method shall follow the requirements of ON.20 (tonnes).

ON.73   Calculation of GHG Emissions

Quantify emissions in accordance with U.S. EPA 40 CFR 98 Subpart F Section 98.63.

ON.74   Sampling, Analysis, and Measurement Requirements

Sampling, analysis and measurement requirements for this source shall be done in accordance with U.S. EPA 40 CFR 98 Subpart F Section 98.64.

ON.75   Procedures for Estimating Missing Data

Missing data requirements for this source shall be estimated in accordance with U.S. EPA 40 CFR 98 Subpart F Section 98.65.

ON.80   Ammonia Manufacturing

ON.81   Source Definition

The ammonia manufacturing source comprises the process units listed in paragraphs (a) and (b) of this section.

(a) Ammonia manufacturing processes in which ammonia is manufactured from a fossil-based feedstock produced via steam reforming of a hydrocarbon.

(b) Ammonia manufacturing processes in which ammonia is manufactured through the gasification of solid and liquid raw material.

ON.82   Greenhouse Gas Reporting Requirements

For the purpose of Section 6 of the Regulation the annual emissions data report for ammonia manufacturing shall include the following information at the facility level calculated in accordance with this method:

(a) CO_2 process emissions from steam reforming of a hydrocarbon or the gasification of solid and liquid raw material following the requirements in this section.

(b) Emissions of CO_2, CH_4, and N_2O from stationary combustion units not covered by this method shall follow the requirements of ON.20 (tonnes).

(c) If a CEMS is used to measure CO_2 emissions, report the relevant information required under ON.23 for Calculation Methodology 4 and the following information in this paragraph:

    (1) Annual quantity of each type of feedstock consumed for ammonia manufacturing (Sm^3 for liquid feedstock or kilolitres for liquid feedstock or tonnes for solid feedstock).

(d) If a CEMS is not used to measure emissions, report the following information:

    (1) Whether carbon content for each feedstock is based on reports from the supplier or analysis of carbon content.

    (2) If a facility uses gaseous feedstock, the carbon content of the gaseous feedstock(kg C per kg of feedstock).

    (3) If a facility uses liquid feedstock, the carbon content of the liquid feedstock, for month n in Equation 80-2, (kg C per kilolitre of feedstock).

    (4) If a facility uses solid feedstock, the carbon content of the solid feedstock, for month n in Equation 80-3, (kg C per kg of feedstock).

    (5) Annual CO_2 emissions associated with the waste recycle stream (tonnes)

    (6) Carbon content of the waste recycle stream (kg C per kg of waste recycle stream).

    (7) Volume of the waste recycle stream (Sm^3)

(e) Annual urea production (tonnes)

ON.83   Calculating GHG emissions

The person must calculate and report the annual process CO_2 emissions from each ammonia manufacturing process unit using the procedures in either paragraph (a) or (b) of this section.

(a) Calculate and report the process CO_2 emissions by operating and maintaining CEMS according to Calculation Methodology 4 specified in ON.23(d) and all associated requirements for methodology 4 in ON.20.

(b) Calculate and report process CO_2 emissions using the procedures in paragraphs (b)(1) through (b)(6) of this section for gaseous feedstock, liquid feedstock, or solid feedstock, as applicable.

(1) Gaseous feedstock. The person must calculate the CO_2 process emissions from gaseous feedstock according to Equation 80-1 of this section:

$$CO_{2,G,k} = (\sum_{n=1}^{12} 3.664 * Fdstk_{n,k} * CC_n * \frac{MW}{MVC}) * 0.001 \quad \textbf{Equation 80-1}$$

Where:

$CO_{2,G,k}$	=	Annual CO_2 emissions arising from feedstock consumption (tonnes).
$Fdstk_{n,k}$	=	Volume of the gaseous' feedstock used in month n (Rm^3 of feedstock) at reference temperature and pressure conditions as used by the facility. If a mass flow meter is used, measure the feedstock used in the month n as kg feedstock and replace the term "MW/MVC" with "1".
CC_n	=	Carbon content of the gaseous feedstock, for month n, (kg C per kg of feedstock), determined according to ON.84(c).
MW	=	Molecular weight of the gaseous feedstock (kg/kg-mole).
MVC	=	Molar volume conversion factor at the same reference conditions as the above $Fdstk_{n,k}$ (Rm3/kg-mole).
	=	8.3145 * [273.16 + reference temperature in °C] / [reference pressure in kilopascal]
3.664	=	Ratio of molecular weights, CO_2 to carbon.
0.001	=	Conversion factor from kg to tonnes.
k	=	Processing unit.
n	=	Number of month

(2) Liquid feedstock. The person must calculate, from each ammonia manufacturing unit, the CO_2 process emissions from liquid feedstock according to Equation 80-2 of this section:

$$CO_{2,L,k} = (\sum_{n=1}^{12} 3.664 * Fdstk_{n,k} * CC_n) * 0.001 \qquad \textbf{Equation 80-2}$$

Where:

$CO_{2,L,k}$ = Annual CO_2 emissions arising from feedstock consumption (tonnes).

$Fdstk_{n,k}$ = Volume of the liquid feedstock used in month n (kilolitres of feedstock). If a mass flow meter is used, measure the feedstock used in month n as kg of feedstock and measure the carbon content of feedstock in kg C per kg of feedstock.

CC_n = Carbon content of the liquid feedstock, for month n as determined according to ON.84(c). (kg of C per kilolitre of feedstock when feedstock consumption is measured in kilolitres or kg of C per kg of feedstock when feedstock consumption is measured in kg.

3.664 = Ratio of molecular weights, CO_2 to carbon.

0.001 = Conversion factor from kg to tonnes.

k = Processing unit.

n = Number of months

(3) Solid feedstock. The person must calculate, from each ammonia manufacturing unit, the CO_2 process emissions from solid feedstock according to Equation 80-3 of this section:

$$CO_{2,S,k} = (\sum_{n=1}^{12} 3.664 * Fdstk_{n,k} * CC_n) * 0.001 \qquad \textbf{Equation 80-3}$$

Where:

$CO_{2,S,k}$ = Annual CO_2 emissions arising from feedstock consumption (tonnes).

$Fdstk_{n,k}$ = Mass of the solid feedstock used in month n (kg of feedstock).

CC_n = Carbon content of the solid feedstock, for month n, (kg C per kg of feedstock), determined according to ON.84(c).

3.664 = Ratio of molecular weights, CO_2 to carbon.

0.001 = Conversion factor from kg to tonnes.

k = Processing unit.

n = Number of month.

(4) The person must calculate the annual process CO_2 emissions from each ammonia processing unit k at the facility summing emissions, as applicable from Equations 80-1, 80-2, and 80-3 of this section using Equation 80-4.

$$E_{CO2_k} = CO_{2,G,k} + CO_{2,S,k} + CO_{2,L,k} \qquad \textbf{Equation 80-4}$$

Where:

E_{CO2k} = Annual CO_2 emissions from each ammonia processing unit k (tonnes).

k = Processing unit.

(5) The person must determine the combined CO_2 emissions from all ammonia processing units at the facility using Equation 80-5 of this section.

$$CO_2 = \sum_{k=1}^{n} E_{CO2k} \qquad \textbf{Equation 80-5}$$

Where:

CO_2 = Annual combined CO_2 emissions from all ammonia processing units (tonnes).

E_{CO2k} = Annual CO_2 emissions from each ammonia processing unit (tonnes).

k = Processing unit.

n = Total number of ammonia processing units.

(6) If applicable, ammonia manufacturing facilities that utilize the waste recycle stream as a fuel must calculate emissions associated with the waste stream for each ammonia process unit according to Equation 80-6 of this section:

$$CO_2 = (\sum_{n=1}^{12} 3.664 * RecycleStream_n * CC_n * \frac{MW}{MVC}) * 0.001 \quad \textbf{Equation 80-6}$$

Where:

CO_2 = Annual CO_2 contained in waste recycle stream (tonnes).

$RecycleStream_n$ = Volume of the waste recycle stream in month n (Rm^3) at reference temperature and pressure conditions as used by the facility. If a mass flow meter is used, measure the waste recycle stream in month n as kg and replace the term "MW/MVC" with "1".

CC_n = Carbon content of the waste recycle stream, for month n, (kg C per kg of waste recycle stream) determined according to ON.84(f).

MW = Molecular weight of the waste recycle stream (kg/kg-mole).

MVC = Molar volume conversion at the same reference conditions as the above $RecycleStream_n$ (Rm3/kg-mole).

= 8.3145 * [273.16 + reference temperature in °C] / [reference pressure in kilopascal].

3.664 = Ratio of molecular weights, CO_2 to carbon.

0.001 = Conversion factor from kg to tonnes.

n = Number of month

(c) If GHG emissions from an ammonia manufacturing unit are vented through the same stack as any combustion unit or process equipment that reports CO_2 emissions using a CEMS that complies with Calculation Methodology 4 in ON.23(d), then the

calculation methodology in paragraph (b) of this section shall not be used to calculate process emissions. The person shall report under this section the combined stack emissions according to Calculation Methodology 4 in ON.23(d) and all associated requirements for Calculation Methodology 4 in ON.20.

ON.84   Sampling, Analysis, and Measurement Requirements

(a) The person must continuously measure the quantity of gaseous or liquid feedstock consumed using a flow meter. The quantity of solid feedstock consumed can be obtained from company records and aggregated on a monthly basis.

(b) The person must document the procedures used to ensure the accuracy of the estimates of feedstock consumption.

(c) The person must determine monthly carbon contents and the average molecular weight of each feedstock consumed from reports from the supplier. As an alternative to using supplier information on carbon contents, the person can also collect a sample of each feedstock on a monthly basis and analyze the carbon content and molecular weight of the fuel using any of the following methods listed in paragraphs (c)(1) through (c)(8) of this section, as applicable.

   (1) ASTM D1945 - Standard Test Method for Analysis of Natural Gas by Gas Chromatography.

   (2) ASTM D1946 - Standard Practice for Analysis of Reformed Gas by Gas Chromatography.

   (3) ASTM D2502 - Standard Test Method for Estimation of Mean Relative Molecular Mass of Petroleum Oils from Viscosity Measurements.

   (4) ASTM D2503 - Standard Test Method for Relative Molecular Mass (Molecular Weight) of Hydrocarbons by Thermoelectric Measurement of Vapor Pressure.

   (5) ASTM D3238 - Standard Test Method for Calculation of Carbon Distribution and Structural Group Analysis of Petroleum Oils by the n-d-M Method.

   (6) ASTM D5291 - Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants.

   (7) ASTM D3176 - Standard Practice for Ultimate Analysis of Coal and Coke.

   (8) ASTM D5373 - Standard Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal.

(d) Calibrate all oil and gas flow meters (except for gas billing meters) and perform oil tank measurements according to the monitoring and QA/QC requirements specified in section ON.25(b)(3).

(e) For quality assurance and quality control of the supplier data, on an annual basis, the person must measure the carbon contents of a representative sample of the feedstocks consumed using the appropriate ASTM Method as listed in paragraphs (c)(1) through (c)(8) of this section.

(f) Facilities must continuously measure the quantity of waste gas recycled using a flow meter, as applicable. The person must determine the carbon content and the molecular weight of the waste recycle stream by collecting a sample of each waste recycle stream on a monthly basis and analyzing the carbon content using the appropriate ASTM Method as listed in paragraphs (c)(1) through (c)(8) of this section.

(g) If CO_2 from ammonia production is used to produce urea at the same facility, the person must determine the quantity of urea produced using methods or plant instruments used for accounting purposes (such as sales records). The person must document the procedures used to ensure the accuracy of the estimates of urea produced.

ON.85   Procedures for Estimating Missing Data

The person is required to retain a complete record of all measured parameters used in the GHG emissions calculations. Therefore, whenever the monitoring and quality assurance procedures in ON.84 cannot be followed (e.g., if a meter malfunctions during unit operation), a substitute data value for the missing parameter shall be used in the calculations following paragraphs (a) and (b) of this section. The person must document and keep records of the procedures used for all such estimates as required by the Regulation.

(a) For missing data on monthly carbon contents of feedstock or the waste recycle stream, the substitute data value shall be the arithmetic average of the quality-assured values of that carbon content in the month preceding and the month immediately following the missing data incident. If no quality-assured data is available prior to the missing data incident, the substitute data value shall be the first quality-assured value for carbon content obtained in the month after the missing data period.

(b) For missing feedstock supply rates or waste recycle stream used to determine monthly feedstock consumption or monthly waste recycle stream quantity, the person must determine the best available estimate(s) of the parameter(s), based on all available process data.

ON.180   Carbonate Use

ON.181   Source Definition

This source includes any equipment that uses one or more carbonates listed in Table 180-1 in manufacturing processes that emit carbon dioxide. Table 180-1 includes the following carbonates: limestone, dolomite, ankerite, magnesite, siderite, rhodochrosite, or sodium carbonate. Facilities are considered to emit CO_2 if they consume at least 1,800 tonnes per year of carbonates heated to a temperature sufficient to allow the calcination reaction to occur.

This source does not include equipment that uses carbonates or carbonate containing minerals that are consumed in the production of cement, copper and nickel, electricity generation, ferroalloys, glass, iron and steel, lead, lime, phosphoric acid, pulp and paper, soda ash, sodium bicarbonate, sodium hydroxide and zinc

This source does not include carbonates used in sorbent technology used to control emissions from stationary fuel combustion equipment. Emissions from carbonates used in sorbent technology are reported under ON.20 (tonnes).

ON.182   Greenhouse Gas Reporting Requirements

For the purpose of Section 6 of the Regulation the annual emissions data report for carbonate use shall include the following information at the facility level calculated in accordance with this method:

(a) Annual CO_2 emissions from miscellaneous carbonate use (tonnes).

(b) If the person followed the calculation methodology contained in ON.183(a), the person must report the following information:

   (1) Annual carbonate consumption by carbonate type (tonnes).

   (2) Annual calcination fractions used in calculations.

(c) If the person followed the calculation methodology contained in ON.183(b), the person must report the following information:

   (1) Annual carbonate input by carbonate type (tonnes).

   (2) Annual carbonate output by carbonate type (tonnes).

(d) Number of times in the reporting year that missing data procedures were followed to measure carbonate consumption, carbonate input or carbonate output (months).

ON.183   Calculating GHG emissions.

The person must determine CO_2 process emissions from carbonate use in accordance with the procedures specified in either paragraph (a) or (b) of this section.

(a) Calculate the process emissions of CO_2 using calcination fractions with Equation 180-1 of this section.

$$E_{CO2} = \sum_{i=1}^{n} \left(M_i \times EF_i \times F_i \right)$$ **Equation 180-1**

Where:

    E_{CO2} =   Annual CO_2 mass emissions from consumption of carbonates (tonnes).

    M_i =   Annual mass of carbonate type i consumed (tonnes).

    EF_i =   Emission factor for the carbonate type i, as specified in Table 180-1 to this section, tonnes CO_2/tonne carbonate consumed.

    F_i =   Fraction calcination achieved for each particular carbonate type i (weight fraction). As an alternative to measuring the calcination fraction, a value of 1.0 can be used.

    n   =   Number of carbonate types.

(b) Calculate the process emissions of CO_2 using actual mass of output carbonates with Equation 180-2 of this section.

$$E_{CO2} = \left[\sum_{k=1}^{m} \left(M_k \times EF_k \right) - \sum_{j=1}^{n} \left(M_j \times EF_j \right) \right]$$ **Equation 180-2**

Where:

    E_{CO2} =   Annual CO_2 mass emissions from consumption of carbonates (tonnes).

    M_k =   Annual mass of input carbonate type k (tonnes).

    EF_k =   Emission factor for the input carbonate type k, as specified in Table 180-1 of this section (tonnes CO_2/tonne carbonate).

    M_j =   Annual mass of output carbonate type j (tonnes).

    EF_j =   Emission factor for the output carbonate type j, as specified in Table 180-1 of this section (tonnes CO_2/tonne carbonate).

    m   =   Number of input carbonate types.

    n   =   Number of output carbonate types.

ON.184   Sampling, Analysis, and Measurement Requirements

(a) The annual mass of carbonate consumed (for Equation 180-1 of this section) or carbonate inputs (for Equation 180-2 of this section) must be determined annually from monthly measurements using the same plant instruments used for accounting purposes including purchase records or direct measurement, such as weigh hoppers or weigh belt feeders.

(b) The annual mass of carbonate outputs (for Equation 180-2 of this section) must be determined annually from monthly measurements using the same plant instruments used for accounting purposes including purchase records or direct measurement, such as weigh hoppers or belt weigh feeders.

(c) If the person follow the procedures of ON.183(a), as an alternative to assuming a calcination fraction of 1.0, the person can determine on an annual basis the calcination fraction for each carbonate consumed based on sampling and chemical analysis using a suitable method such as using an x-ray fluorescence standard method or other enhanced industry consensus standard method published by an industry consensus standard organization (e.g., ASTM, ASME, etc.).

ON.185   Procedures for Estimating Missing Data.

The person is required to retain a complete record of all measured parameters used in the GHG emissions calculations. Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter shall be used in the calculations as specified in paragraph (a) of this section. The person must document and keep records of the procedures used for all such estimates as required by the Regulation.

(a) For each missing value of monthly carbonate consumed, monthly carbonate output, or monthly carbonate input, the substitute data value must be the best available estimate based on the all available process data or data used for accounting purposes (such as sales records).

Table 180-1—CO$_2$ Emission Factors for Common Carbonates

Mineral Name – Carbonate	CO$_2$ Emission Factor (tonnes CO$_2$/tonne carbonate)
Limestone - CaCO$_3$	0.43971
Magnesite - MgCO$_3$	0.52197
Dolomite - CaMg(CO$_3$)$_2$	0.47732
Siderite - FeCO$_3$	0.37987
Ankerite - Ca(Fe,Mg,Mn)(CO$_3$)$_2$	0.47572
Rhodochrosite - MnCO$_3$	0.38286
Sodium Carbonate/Soda Ash – Na$_2$CO$_3$	0.41492
Others	Facility specific factor to be determined through analysis or supplier information or using stoichiometric ratio

ON.90   Cement Manufacturing

ON.91   Source Definition

Cement manufacturing is comprised of all processes that are used to manufacture Portland, natural, masonry, pozzolanic, or other hydraulic cements.

ON.92   Greenhouse Gas Reporting Requirements

For the purpose of Section 6 of the Regulation the annual emissions data report for cement manufacturing shall include the following information at the facility level calculated in accordance with this method:

(a) Total emissions of CO_2, CH_4, and N_2O in tonnes.

(b) Annual CO_2 process emissions from calcination (tonnes) and the following information:

(1) Monthly plant specific clinker emission factors (tonnes CO_2/tonnes clinker).

    (i)   Monthly quantities of clinker produced (tonnes).

    (ii)   Monthly total calcium content of clinker, expressed as calcium oxide (CaO) (weight fraction, tonne CaO/tonne clinker).

    (iii) Monthly total magnesium content of clinker, expressed as magnesium oxide (MgO) (weight fraction, tonne MgO/tonne clinker).

    (iv)   Monthly non-calcined calcium oxide content of clinker, expressed as CaO (weight fraction, tonne CaO/tonne clinker).

    (v)   Monthly non-calcined magnesium oxide content of clinker, expressed as MgO (weight fraction, tonne MgO/tonne clinker).

    (vi)   Monthly quantity of non-carbonate raw materials entering the kiln (tonnes).

(2) Quarterly cement kiln dust (CKD) emission factor (tonne CO_2/tonne CKD not recycled back to kilns).

    (i)   Quarterly quantity of CKD not recycled back to kilns (tonnes).

(c) Annual CO_2 process emissions from organic carbon oxidation (tonnes) and the following information:

(1) Amount of raw material consumed in the report year (tonnes).

(2) Annual organic carbon content of raw material (weight. fraction).

(d) Annual CO_2, CH_4, and N_2O emissions from fuel combustion in all kilns combined, following the calculation methodology and reporting requirements specified in ON.93(c) (tonnes).

(e) Annual CO_2, CH_4, and N_2O emissions from all other fuel combustion units combined (kilns excluded), following the calculation methodology and reporting requirements specified in ON.20 (tonnes).

(f) If a continuous emissions monitor is used to measure CO_2 emissions from kilns, then the requirements of paragraphs (b) and (c) of this section do not apply for CO_2. Cement plants that measure CO_2 emissions using CEMS shall report fuel usage by fuel type for kilns.

(g) Operators of cement plants shall also comply with the reporting requirements for any other applicable source listed by regulation, including but not limited to the following:

(1) Coal fuel storage as specified in ON.100.

(2) Electricity generating as specified in ON.40.

(3) Cogeneration systems as specified in ON.42(f).

(h) Number of times missing data procedures were used to determine clinker production, non-calcined calcium oxide, magnesium oxide content of clinker, CKD not recycled, non-calcined calcium oxide, magnesium oxide content of CKD, organic carbon content, and raw material consumption.

ON.93   Calculation of Greenhouse Gas Emissions from Kilns

(a) Determine CO_2 emissions as specified under either paragraph (a)(1) or (a)(2) of this section.

(1) Calculate the total process and combustion CO_2 emissions from all the kilns using a continuous emissions monitoring system (CEMS) as specified in ON.23(d) and combustion CO_2 emissions from all the kilns using the calculation methodologies specified in paragraph (c) of this section.

(2) Calculate the sum of CO_2 process emissions from kilns and CO_2 fuel combustion emissions from kilns using the calculation methodologies specified in paragraphs (b) and (c) of this section.

(b) Process CO_2 Emissions Calculation Methodology. Calculate total CO_2 process emissions as the sum of emissions from calcination, using the method specified in paragraph (b)(1) of this section; and from organic carbon oxidation, using the method specified in paragraph (b)(2) of this section (Equation 90-1).

$$E_{CO2-P} = E_{CO2-C} + E_{CO2-F} \qquad \textbf{Equation 90-1}$$

Where:

$\qquad E_{CO2-P}$ =   Annual process CO_2 emissions, tonnes/year.
$\qquad E_{CO2-C}$ =   Annual process CO_2 emissions from calcination, tonnes/year.
$\qquad E_{CO2-F}$ =   Annual process CO_2 emissions from feed oxidation, tonnes/year.

(1) Calcination Emissions. Calculate CO_2 process emissions from calcination using Equation 90-2 and a plant-specific clinker emission factor and a plant-specific cement kiln dust (CKD) emission factor as specified in this section.

$$E_{CO2-C} = \sum_{m=1}^{12}\left[Q_{Cli,m} \times EF_{Cli,m}\right] + \sum_{q}^{4}\left[Q_{CKD,q} \times EF_{CKD,q}\right] \qquad \textbf{Equation 90-2}$$

Where:

E_{CO2-C} = Annual process CO_2 emissions from calcination, tonnes.
$Q_{Cli,m}$ = Quantity of clinker produced in month m, tonnes.
$EF_{Cli,m}$ = CO_2 emission factor for clinker in month m, computed as specified in paragraph (b)(1)(i) of this section, tonnes CO_2/tonne clinker.
$Q_{CKD,q}$ = Quantity CKD not recycled to kilns in quarter q, tonnes.
$EF_{CKD,q}$ = CO_2 emission factor for CKD not recycled to the kilns, computed as specified in paragraph (b)(1)(ii) of this section, tonnes CO_2/tonne CKD.

(i) Clinker Emission Factor. Calculate a plant-specific clinker emission factor (EF_{Cli}) for each month based on monthly measurements of the weight fractions of calcium (as CaO) and magnesium (as MgO) content in the clinker and in the non-carbonate raw materials entering the kiln, using Equation 90-3,.

$$EF_{Cli} = (CaO_{Cli} - CaO_f) \times 0.785 + (MgO_{Cli} - MgO_f) \times 1.092$$

Equation 90-3

Where:

EF_{Cli} = Monthly CO_2 emission factor for clinker, tonne CO_2/tonne clinker
CaO_{Cli} = Monthly total calcium content of clinker expressed as calcium oxide, tonne CaO/tonne clinker.
CaO_f = Monthly non-calcined calcium oxide content of clinker, tonne CaO/tonne clinker.
MgO_{Cli} = Monthly total magnesium content of clinker expressed as magnesium oxide, tonne MgO/tonne clinker.
MgO_f = Monthly non-calcined magnesium oxide content of clinker, tonne MgO/tonne clinker.
0.785 = Ratio of molecular weights of CO_2 to CaO
1.092 = Ratio of molecular weights of CO_2 to MgO

(ii) CKD Emission Factor. If CKD is generated and not recycled back to the kilns, then calculate a plant-specific CKD emission factor based on quarterly sampling. The CKD emission factor shall be calculated using Equation 90-4.

$$EF_{CKD} = (CaO_{CKD} - CaO_f) \times 0.785 + (MgO_{CKD} - MgO_f) \times 1.092$$

Equation 90-4

Where:

EF_{CKD} = Quarterly CO_2 emission factor for CKD not recycled to the kilns, tonne CO_2/tonne CKD.
CaO_{CKD} = Quarterly total calcium oxide content of CKD not recycled to the kilns, tonne CaO/tonne CKD.

CaO_f =   Quarterly non-calcined calcium oxide content of CKD not recycled to the kilns, tonne CaO/tonne CKD.

MgO_{CKD} =   Quarterly total magnesium oxide content of CKD not recycled to the kilns, tonne MgO/tonne CKD.

MgO_f =   Quarterly non-calcined magnesium oxide content of CKD not recycled to the kilns, tonne MgO/tonne CKD.

0.785   =   Ratio of molecular weights of CO_2 to CaO

1.092   =   Ratio of molecular weights of CO_2 to MgO

(2) Organic Carbon Oxidation Emissions. Calculate CO_2 process emissions from the total organic content in raw materials by using Equation 90-5.

$$E_{CO_{2-RM}} = TOC_{RM} \times RM \times 3.664$$ **Equation 90-5**

Where:

$E_{CO2\text{-}RM}$ =   Annual process CO_2 emissions from raw material oxidation, tonnes.

TOC_{RM} =   Total organic carbon content in raw material (weight. fraction), measured using the method in ON.94(b) or using a default of 0.002 (0.2%).

RM   =   Amount of raw material consumed (tonnes/year).

3.664   =   Ratio of molecular weights of carbon dioxide to carbon.

(c) Fuel Combustion Emissions in Kilns. Calculate CO_2, CH_4, and N_2O emissions from stationary fuel combustion in accordance with the calculation methodologies specified in ON.20. Cement plants that combust pure biomass-derived fuels and combust fossil fuels only during periods of start-up, shut-down, or malfunction may report CO_2 emissions from fossil fuels using the emission factor methodology in ON.23(a). "Pure" means that the biomass-derived fuels account for at least 97 per cent of the total amount of carbon in the fuels burned.

ON.94   Sampling, Analysis, and Measurement Requirements

(a) Determine the monthly plant-specific weight fractions of total calcium (as CaO) and total magnesium (as MgO) in clinker using ASTM C114, an equivalent industry method or a method approved by the Director. The monitoring must be conducted either daily from clinker drawn from the exit of the kiln or monthly from clinker drawn from bulk storage.

(b) Determine quarterly the plant-specific weight fractions of total calcium (as CaO) and total magnesium (as MgO) in CKD using ASTM C114, an equivalent industry method or a method approved by the Director. The monitoring must be conducted daily from CKD samples drawn from the exit of the kiln or quarterly from CKD samples drawn from bulk storage.

(c) Determine monthly the plant-specific weight fractions of calcium oxide (CaO) and magnesium oxide (MgO) that enters the kiln as a non-carbonate species to clinker by

chemical analysis of feed material using documented analytical method or the appropriate industrial standard practice, or use a value of 0.0.

(d) Determine quarterly the plant-specific weight fractions of calcium oxide (CaO) and magnesium oxide (MgO) that enters the kiln as a non-carbonate species to CKD by chemical analysis of feed material using documented analytical method or the appropriate industrial standard practice, or use a value of 0.0.

(e) Determine monthly the plant-specific weight fractions of calcium oxide (CaO) and magnesium oxide (MgO) that remains in clinker by chemical analysis of feed material using documented analytical method or the appropriate industrial standard practice, or use a value of 0.0.

(f) Determine quarterly the plant-specific weight fractions of calcium oxide (CaO) and magnesium oxide (MgO) that remains in CKD by chemical analysis of feed material using documented analytical method or the appropriate industrial standard practice, or use a value of 0.0.

(g) Determine annually the total organic carbon contents of raw materials using ASTM C114, an equivalent industry method or method approved for total organic carbon determination in raw mineral material, or use a default value of 0.002. The analysis must be conducted on sample material drawn from bulk raw material storage for each category of raw material.

(h) The quantity of clinker produced must be determined by monthly by either:

(1) Direct weight measurement using the same plant techniques used for accounting purposes, such as reconciling weigh hoppers or belt weigh feeders measurements against inventory measurements, or

(2) Direct measurement of raw kiln feed and application of a kiln-specific feed-to-clinker factor. Facilities that opt to use a feed to clinker factor must verify the accuracy of this factor on a monthly basis.

(i) The quantity of CKD not recycled back to the kiln must be determined quarterly by either using the same plant techniques used for accounting purposes, such as direct weight measurement using weigh hoppers or belt weigh feeders, and/or material balances.

(j) The quantity of raw materials consumed (i.e. limestone, sand, shale, iron oxide, alumina, and non-carbonate raw material) must be determined monthly by direct weight measurement using the same plant instruments used for accounting purposes, such as weigh hoppers or belt weigh feeders.

ON.95   Procedures for Estimating Missing Data

The person is required to retain a complete record of all measured parameters used in the GHG emissions calculations. Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter shall be used in the calculations. The person must document and keep records of the procedures used for all such estimates as required by the Regulation.

(a) If the CEMS approach is used to determine combined process and combustion CO_2 emissions, the missing data procedures in ON.20 apply.

(b) For CO_2 process emissions from cement manufacturing facilities calculated according to ON.93(b), if data on the carbonate content (of clinker or CKD), noncalcined content (of clinker or CKD) or the annual organic carbon content of raw materials are missing, facilities must undertake a new analysis.

(c) For each missing value of monthly clinker production, the substitute data value must be the best available estimate of the monthly clinker production based on information used for accounting purposes (such as purchase record), or use the maximum tonnes per day capacity of the system and the number of days per month.

(d) For each missing value of monthly raw material consumption, the substitute data value must be the best available estimate of the monthly raw material consumption based on information used for accounting purposes (such as purchase records), or use the maximum tonnes per day raw material throughput of the kiln and the number of days per month.

ON.100 Coal Storage

ON.101 Source Definition

Coal storage piles are located at any facilities that combust coal. Coal storage piles release fugitive CH_4 emissions.

ON.102 Greenhouse Gas Reporting Requirements

For the purpose of Section 6 of the Regulation the annual emissions data report for coal storage shall include the following information at the facility level calculated in accordance with this method:

(a) Annual greenhouse gas emissions in tonnes, reported as follows:

  (1) Total CH_4 emissions.

(b) Annual coal purchases (tons for U.S.; tonnes for Canada).

(c) Source of coal purchases:

  (1) Coal basin.

  (2) State/province.

  (3) Coal mine type (surface or underground).

ON.103 Calculation of CH_4 Emissions

Calculate fugitive CH_4 emissions from coal storage piles as specified under paragraph (a), (b), or (c) of this section.

(a) For coal purchased from U.S. sources, calculate fugitive CH_4 emissions using Equation 100-1 and Table 100-1.

(b) For coal purchased from Canadian sources, calculate fugitive CH_4 emissions using Equation 100-1 and Table 100-2.

(c) For coal purchased from non-U.S. and non-Canadian sources, the person should use either ON.103(a) or ON.103(b), whichever is the most applicable. This chosen approach is subject to approval in writing by the Director.

$$CH_4 = \sum_i \left(PC_i \times EF_i \right) \times 0.6772 \, / \, 1{,}000$$

Equation 100-1

Where:

  CH_4 =   Fugitive emissions from coal storage piles for each coal category i, (tonnes CH_4 per year);

  PC_i =   Purchased coal for each coal category i (tonnes per year);

EF_i =   Default CH_4 emission factor for each coal category i specified by
                  location and mine type that coal originated from, provided in Table
                  100-2 (m³ CH_4 per tonne of coal);

0.6772   =   Methane conversion factor to convert m³ to kg;

1,000   =   Factor to convert kg to tonnes.

ON.104   Sampling, Analysis, and Measurement Requirements

(a) Coal Purchase Monitoring Requirements.

Facilities may determine the quantity of coal purchased either using records provided
by the coal supplier(s) or monitoring coal purchase quantities using the same plant
instruments used for accounting purposes, such as weigh hoppers or belt weigh
feeders.

ON.105   Procedures for Estimating Missing Data

The person is required to retain a complete record of all measured parameters used in the
GHG emissions calculations. Whenever a quality-assured value of a required parameter
is unavailable (e.g., if a meter malfunctions during unit operation), a substitute data value
for the missing parameter must be used in the calculations as specified in paragraph (a) of
this section:

(a) For missing feedstock and production values, the substitute data value shall be the
    best available estimate of the parameter, based on all available process data. The
    person must document and retain records of the procedures used for all such
    estimates.

Table 100-1. U.S. Default Fugitive Methane Emission Factors from Post-Mining Coal Storage and Handling (CH₄ m³ per Tonne)			
Coal Origin		Coal Mine Type	
Coal Basin	States	Surface Post-Mining Factors	Underground Post-Mining Factors
Northern Appalachia	Maryland, Ohio, Pennsylvania, West Virginia North	0.6025	1.4048
Central Appalachia (WV)	Tennessee, West Virginia South	0.2529	1.3892
Central Appalachia (VA)	Virginia	0.2529	4.0490
Central Appalachia (E KY)	East Kentucky	0.2529	0.6244
Warrior	Alabama, Mississippi	0.3122	2.7066
Illinois	Illinois, Indiana, Kentucky West	0.3465	0.6525
Rockies (Piceance Basin)	Arizona, California, Colorado, New Mexico, Utah	0.3372	1.9917
Rockies (Uinta Basin)		0.1623	1.0083
Rockies (San Juan Basin)		0.0749	1.0645
Rockies (Green River Basin)		0.3372	2.5068
Rockies (Raton Basin)		0.3372	1.2987
N. Great Plains	Montana, North Dakota, Wyoming	0.0562	0.1592

West Interior (Forest City, Cherokee Basins)	Arkansas, Iowa, Kansas, Louisiana, Missouri, Oklahoma, Texas	0.3465	0.6525
West Interior (Arkoma Basin)		0.7555	3.3591
West Interior (Gulf Coast Basin)		0.3372	1.2987
Northwest (AK)	Alaska	0.0562	1.6233
Northwest (WA)	Washington	0.0562	0.5900

Source: *Inventory of U.S. Greenhouse Gas Emissions and Sinks:1990 – 2005*
April 15, 2007, U.S. Environmental Protection Agency. Annex 3, Methodological Descriptions for Additional Source or Sink Categories, Section 3.3, Table A-115, Coal Surface and Post-Mining CH_4 Emission Factors (ft^3 per Short Ton; converted to m^3 per tonne). (Only Post-Mining EFs used from Table). State assignments shown from Table 113 of Annex 3.

Table 100-2. Canada Default Fugitive Methane Emission Factors from Post-Mining Coal Storage and Handling (CH_4 m^3 per tonne)			
Coal Origin		Coal Mine Type	
Province	Coalfield	Surface Post-Mining Factors	Underground Post-Mining Factors
British Columbia	Comox	0.500	n/a
	Crowness	0.169	n/a
	Elk Valley	0.900	n/a
	Peace River	0.361	n/a
	Province Average	0.521	n/a
Alberta	Battle River	0.067	n/a
	Cadomin-Luscar	0.709	n/a
	Coalspur	0.314	n/a
	Obed Mountain	0.238	n/a
	Sheerness	0.048	n/a
	Smokey River	0.125	0.067
	Wabamun	0.176	n/a
	Province Average	0.263	0.067
Saskatchewan	Estavan	0.055	n/a
	Willow Bunch	0.053	n/a
	Province Average	0.054	n/a
New Brunswick	Province Average	0.060	n/a
Nova Scotia	Province Average	n/a	2.923

Source: *Management of Methane Emissions from Coal Mines: Environmental, Engineering, Economic and Institutional Implications of Options.* Prepared by Brian G. King, Neill and Gunter (Nova Scotia) Limited, Darmouth, Nova Scotia for Environment Canada. Contract Number K2031-3-7062. March 1994. This document is cited by Environment Canada in the NIR 1990-2007 (Final Submission, April 2009), , but post-mining emission factors are not provided, so they were developed for WCI purposes by Province. Surface emission factors were derived from Table 3.1 (Coal production statistics [Column A] and post-mining emissions [Column F]). Underground emission factors were derived from Table 3.2 (Coal production statistics and post-mining emissions).

ON.260   Copper and Nickel Production

ON.261   Source Definition

The nickel and copper metal production source includes process-related sources at nickel and copper metal smelting and refining facilities. Metals addressed in other categories (i.e., iron and steel, ferroalloys, aluminum, magnesium, lead, and zinc) are not included in this source.

The nickel and copper metal production source includes three main processes that produce CO_2 emissions: removal of impurities from nickel or copper ore concentrate using carbonate flux reagents (i.e., limestone [$CaCO3$] or dolomite [$CaCO3 \cdot MgCO3$]), the use of other reducing agents to extract metals from their oxides (e.g., metallurgical coke, coal, natural gas, etc.), and the use of material (e.g., coke) for slag cleaning and the consumption of graphite or carbon electrodes in electric arc furnaces. It is important to distinguish between fuels used for combustion and fuels used as reducing agents; only fuels used as reducing agents should be included in the base metal production source. Fuels used for combustion are reported in ON.20.

ON.262   Greenhouse Gas Reporting Requirements

For the purpose of Section 6 of the Regulation the annual emissions data report for copper and nickel production shall include the following information at the facility level calculated in accordance with this method:

(a) Annual emissions of CO_2 at the facility level (tonnes).

(b) Annual quantities of each carbonate flux reagent used (tonnes).

(c) Fractional purity of each carbonate flux reagent used (tonnes carbonate/tonnes reagent).

(d) Annual quantities of other reducing agents used (tonnes).

(e) Carbon content of other reducing agent used or material used for slag cleaning (tonnes C/tonne reducing agent or material for slag cleaning).

(f) Annual quantity of ore processed (tonnes).

(g) Carbon content of ore processed (tonnes C/tonne ore).

ON.263   Calculation of CO_2 Emissions

Calculate total CO_2 emissions as specified under paragraph (a) through (d) of this section.

(a) Calculate CO_2 emissions from carbonate flux reagents using Equation 260-1.

$$E_{cf} = Q_{ls} \times f_{ls} \times \left(\frac{44}{100}\right) + Q_d \times f_d \times \left(\frac{88}{184}\right)$$

Equation 260-1

Where:

E_{cf} = Annual CO_2 emissions from carbonate flux reagents (tonnes);
Q_{ls} = Annual quantity of limestone consumed (tonnes);
f_{ls} = Fractional purity of limestone (tonnes $CaCO_3$/tonnes of material);

44/100   =   Stoichiometric conversion factor from $CaCO_3$ to CO_2;
Q_d =   Annual quantity of dolomite consumed (tonnes);
f_d =   Fractional purity of dolomite (tonnes $CaCO_3 \cdot MgCO_3$/tonnes of material);
88/184   =   Stoichiometric conversion factor from $CaCO_3 \cdot MgCO_3$ to CO_2.

(b) Calculate CO_2 emissions from other reducing agents or material used in slag cleaning using Equation 260-2.

$$E_{ra} = Q_a \times C_a \times 3.664$$

Equation 260-2

Where:

E_{ra} =   Annual CO_2 emissions from other reducing agents or material used for slag cleaning (tonnes);

Q_a =   Annual quantity of other reducing agents or material used for slag cleaning (tonnes);

C_a =   Carbon content of other reducing agents or material used for slag cleaning (tonnes C/tonne of reducing agent or material used for slag cleaning);

3.664   =   ratio of molecular weights, carbon dioxide to carbon.

(c) Calculate CO_2 emissions from release of carbon from metal ores using Equation 260-3.

$$E_{ore} = Q_{ore} \times C_{ore} \times 3.664$$

Equation 260-3

Where:

E_{ore} =   Annual process CO_2 emissions from metal ore, tonnes
Q_{ore} =   Annual quantity of nickel or copper metal ore consumed (tonnes);
C_{ore} =   Carbon content of nickel or copper metal ore (tonnes C/tonne of nickel or copper ore);
3.664   =   ratio of molecular weights, carbon dioxide to carbon.

(d) Calculate CO_2 emissions from carbon electrode consumption in electric arc furnaces (EAFs) using Equation 260-4.

$$E_{ce} = Q_{ce} \times C_{ce} \times 3.664$$

Equation 260-4

Where:

E_{ce} =   Annual CO_2 emissions from carbon electrode consumption in EAFs (tonnes);

Q_{ce} =   Quantity of carbon electrodes consumed (tonnes);

C_{ce} =   Carbon content of carbon electrodes (tonnes C/tonne carbon electrodes);

3.664   =   ratio of molecular weights, carbon dioxide to carbon.

ON.264   Sampling, Analysis, and Measurement Requirements

The annual mass of each solid carbon-containing input material consumed shall be determined using facility instruments, procedures, or records used for accounting purposes, including either direct measurement of the quantity of the material consumed or by calculations using process operating information.

The average carbon content of each material consumed shall be determined as specified under paragraph (a) or (b) of this section.

(a) Obtain carbon content by collecting and analyzing at least three representative samples of the material each year using one of the following methods:

   (1) For coal and coke, use ASTM D5373 - Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal and Coke.

   (2) For petroleum-based liquid fuels and liquid waste-derived fuels, use ASTM D5291 - Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants, ultimate analysis of oil or computations based on ASTM D3238 and either ASTM D2502 or ASTM D2503.

   (3) For gaseous fuels, use ASTM D1945 or ASTM D1946.

   (4) For carbonate flux reagents (i.e., limestone and dolomite), use ASTM C25 - Standard Test Methods for Chemical Analysis of Limestone, Quicklime, and Hydrated Lime.

(b) Obtain carbon content of the materials, including carbon electrodes, from the vendor or supplier.

ON.265   Procedures for Estimating Missing Data

For the carbon input procedure in ON.263, the person is required to retain a complete record of all measured parameters used in the GHG emissions calculations (e.g., raw materials carbon content values, etc.). Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter shall be used in the calculations as specified in paragraphs (a) and (b) of this section. The person must document and keep records of the procedures used for all such estimates as required by the Regulation.

(a) For missing records of the carbon content of inputs for facilities that estimate emissions using the carbon input procedure in ON.263, 100 per cent data availability is required. The person must repeat the test for average carbon contents of inputs according to the procedures in ON.264 if data is missing.

(b) For missing records of the annual mass of carbon-containing inputs using the carbon input procedure in ON.263, the substitute data value must be based on the best available estimate of the mass of the input material from all available process data or information used for accounting purposes, such as purchase records.

ON.40   Electricity Generation

ON.41   Source Definition

An electricity generating unit is any combustion device that combusts solid, liquid, or gaseous fuel for the purpose of producing electricity either for sale or for use onsite. This source includes cogeneration (combined heat and power) units. This source does not include portable or emergency generators less than 10 MW in nameplate generating capacity as defined in Section 2 of the Guideline.

ON.42   Greenhouse Gas Reporting Requirements

For the purpose of Section 6 of the Regulation the annual emissions data report for electricity generation shall include the following information at the facility level calculated in accordance with this method:

(a) Annual greenhouse gas emissions in tonnes, reported as follows:

   (1) Total CO_2 emissions for fossil fuels, reported by fuel type.

   (2) Total CO_2 emissions for all biomass fuels combined.

   (3) Total CH_4 emissions for all fuels combined.

   (4) Total N_2O emissions for all fuels combined.

(b) Annual fuel consumption:

   (1) For gases, report in units of standard cubic meters.

   (2) For liquids, report in units of kilolitres.

   (3) For non-biomass solids, report in units of tonnes.

   (4) For biomass-derived solid fuels, report in units of bone dry tonnes.

(c) Annual weighted average carbon content of each fuel, if used to compute CO_2 emissions as specified in ON.43.

(d) Annual weighted average high heating value of each fuel, if used to compute CO_2 emissions as specified ON.43.

(e) The nameplate generating capacity in megawatts (MW) and net power generated in the reporting year in megawatt hours (MWh).

(f) For each cogeneration unit, indicate whether topping or bottoming cycle and provide useful thermal output as applicable, in MJ. Where steam or heat is acquired from another facility for the generation of electricity, report the provider and amount of acquired steam or heat in MJ. Where supplemental firing has been applied to support electricity generation, report this purpose and fuel consumption by fuel type using the units in ON.42(b).

(g) Process CO_2 emissions from acid gas scrubbers and acid gas reagent.

(h) Fugitive emissions of each of the HFCs in Table 1 of the Regulation from cooling units that support power generation.

(i) Fugitive CO_2 emissions from geothermal facilities.

(j) Fugitive CH_4 emissions from coal storage at coal-fired electricity generating facilities shall be reported as specified in section ON.100.

ON.43   Calculation of Greenhouse Gas Emissions

(a) Calculation of CO_2 Emissions. The person shall use CEMS to measure CO_2 emissions if required to operate a CO_2 CEMS with flow monitors by any other federal or provincial regulation. A person not required to operate a CEMS by another regulation may use either CEMS or the calculation methodologies specified in paragraphs (a)(1) through (a)(7). The person using CEMS to determine CO_2 emissions shall comply with the provisions in section ON.23(d).

(1) Natural Gas and fuels in Table 20-1a. For electric generating units combusting natural gas or the fuels listed in Table 20-1a, use methods in accordance with ON.23.

(2) Coal or Petroleum Coke. For electric generating units combusting coal or petroleum coke, use the measured carbon content of the fuel and Calculation Methodology 3 in section ON.23(c).

(3) Middle Distillates, Gasoline, Residual Oil, or Liquid Petroleum Gases that are not listed in Table 20-1a. For electric generating units combusting middle distillates, gasoline, residual oil, or LPG that are not listed in Table 20-1a, use one of the following methods:

    (i) The measured carbon content of the fuel and Calculation Methodology 3 in section ON.23(c); or

    (ii) The measured heat content of the fuel and Calculation Methodology 2 in section ON.23(b) provided the facility is not subject to the Regulation.

(4) Refinery Fuel Gas, Flexigas, or Associated Gas. For electric generating units combusting refinery fuel gas, flexigas, or associated gas, use the methods specified in section ON.30.

(5) Landfill Gas, Biogas, or Biomass. For electric generating units combusting landfill gas, biogas, or biomass, use methods in accordance with ON.23.

(6) Municipal Solid Waste. Electric generating units combusting municipal solid waste, may use the measured steam generated, the default emission factor in ON.20 Table 20-7, and the Calculation Methodology 2 in section ON.23(b)(2) provided the facility is not subject to the Regulation. If the facility is subject to the Regulation, the person shall use CEMS to measure CO_2 emissions in accordance with ON.23(d), or calculate emissions using steam flow and a CO_2 emission factor according to the provisions of ON.23(c)(2).

(7) Start-up Fuels. The persons of generating facilities that primarily combust biomass-derived fuels but combust fossil fuels during start-up, shut-down, or malfunction operating periods only, shall calculate CO_2 emissions from fossil fuel combustion using one of the following methods. Malfunction means the unplanned outage of equipment; breakdown of equipment; or failure of equipment

to operate normally, associated with the operation of a combustion device for an electricity generation unit(s). It does not include normal changes in operation conditions such as variations in combustion temperature, oxygen levels or moisture content of the fuel.

    (i) The default emission factors from Tables 20-1a, 20-2, 20-3, 20-5 or 20-7, and default HHV from Tables 20-1 or 20-1a, as applicable, and Calculation Methodology 1 provided in section ON.23(a);

    (ii) The measured heat content of the fuel and Calculation Methodology 2 provided in section ON.23(b);

    (iii) The measured carbon content of the fuel and Calculation Methodology 3 provided in section ON.23(c); or

    (iv) For combustion of refinery fuel gas, the measured heat content and carbon content of the fuel, and the calculation methodology provided in section ON.30.

(8) Co-fired Electricity Generating Units. For electricity generating units that combust more than one type of fuel, the person shall calculate CO_2 emissions as follows.

    (i) For co-fired electricity generators that burn only fossil fuels, CO_2 emissions shall be determined using one of the following methods:

        (A) A continuous emission monitoring system in accordance with Calculation Methodology 4 in section ON.23(d). The person using this method needs not report emissions separately for each fossil fuel.

        (B) For units not equipped with a continuous emission system, calculate the CO_2 emissions separately for each fuel type using the methods specified in paragraphs (a)(1) through (a)(4) of this section.

    (ii) For co-fired electricity generators that burn biomass-derived fuel with a fossil fuel, CO_2 emissions shall be determined using one of the following methods:

        (A) A continuous emission monitoring system in accordance with Calculation Methodology 4 in section ON.23(d). The person using this method shall determine the portion of the total CO_2 emissions attributable to the biomass-derived fuel and portion of the total CO_2 emissions attributable to the fossil fuel using the methods specified in section ON.23(d)(4).

        (B) For units not equipped with a continuous emission system, calculate the CO_2 emissions separately for each fuel type using the methods specified in paragraphs (a)(1) through (a)(7) of section ON.43(a).

(b) Calculation of CH_4 and N_2O Emissions. Operators of electricity generating units shall use the methods specified in section ON.24 to calculate the annual CH_4 and N_2O

emissions. For coal combustion, use the default CH_4 emission factor(s) in Table 20-6.

(c) Calculation of CO_2 Emissions from Acid Gas Scrubbing. Operators of electricity generating units that use acid gas scrubbers or add an acid gas reagent to the combustion unit shall calculate the annual CO_2 emissions from these processes using Equation 40-1 if these emissions are not already captured in CO_2 emissions determined using a continuous emissions monitoring system.

$$CO_2 = S \times R \times \left(CO_{2\,MW} / Sorbent_{MW}\right)$$ **Equation 40-1**

Where:

CO_2	=	CO_2 emitted from sorbent for the report year, tonnes;
S	=	Limestone or other sorbent used in the report year, tonnes;
R	=	Ratio of moles of CO_2 released upon capture of one mole of acid gas;
$CO_{2\,MW}$	=	Molecular weight of carbon dioxide (44);
$Sorbent_{MW}$	=	Molecular weight of sorbent (if calcium carbonate, 100).

(d) Calculating Fugitive HFC Emissions from Cooling Units. Operators of electricity generating facilities shall calculate fugitive HFC emissions for each HFC compound used in cooling units that support power generation or are used in heat transfers to cool stack gases using either the methodology in paragraph (d)(1) or (d)(2).   The person is not required to report GHG emissions from air or water cooling systems or condensers that do not contain HFCs, or from heating ventilation and air conditioning systems used for cooling of control rooms, offices and buildings at the facility.

   (1)   Use Equation 40-2 to calculate annual HFC emissions:

$$HFC = HFC_{inventory} + HFC_{purchases\,/\,acquisitions} - HFC_{sales\,/\,disbursements} + HFC_{\Delta capacity}$$ **Equation 40-2**

Where:

HFC	=	Annual fugitive HFC emission, tonnes;
$HFC_{inventory}$	=	The difference between the quantity of HFC in storage at the beginning of the year and the quantity in storage at the end of the year. Stored HFC includes HFC contained in cylinders (such as 115-pound storage cylinders), gas carts, and other storage containers. It does not include HFC gas held in operating equipment. The change in inventory will be negative if the quantity of HFC in storage increases over the course of the year.
$HFC_{purchases/acquisitions}$	=	The sum of all HFC acquired from other entities during the year either in storage containers or in equipment.
$HFC_{sales/disbursements}$	=	The sum of all the HFC sold or otherwise transferred offsite to other entities during the year either in storage containers or in equipment.
$HFC_{\Delta capacity}$	=	The net change in the total nameplate capacity (i.e. the full and proper charge) of the cooling equipment. The net change in

capacity will be negative if the total nameplate capacity at the end of the year is less than the total nameplate capacity at the beginning of the year.

(2) Use service logs to document HFC usage and emissions from each cooling unit. Service logs should document all maintenance and service performed on the unit during the report year, including the quantity of HFCs added to or removed from the unit, and include a record at the beginning and end of each report year. The person may use service log information along with the following simplified material balance equations to quantify fugitive HFCs from unit installation, servicing, and retirement, as applicable. The person shall include the sum of HFC emissions from the applicable equations in the greenhouse gas emissions data report.

$$HFC_{Install} = R_{new} - C_{new} \qquad \textbf{Equation 40-2a}$$

$$HFC_{Service} = R_{recharge} - R_{Recover} \qquad \textbf{Equation 40-2b}$$

$$HFC_{Retire} = C_{retire} - R_{retire} \qquad \textbf{Equation 40-2c}$$

Where:

$HFC_{Install}$ = HFC emitted during initial charging/installation of the unit, kilograms;

$HFC_{Service}$ = HFC emitted during use and servicing of the unit for the report year, kilograms;

HFC_{Retire} = HFC emitted during the removal from service/retirement of the unit, kilograms;

R_{new} = HFC used to fill new unit (omit if unit was pre-charged by the manufacturer), kilograms;

C_{new} = Nameplate capacity of new unit (omit if unit was pre-charged by the manufacturer), kilograms;

$R_{recharge}$ = HFC used to recharge the unit during maintenance and service, kilograms;

$R_{recover}$ = HFC recovered from the unit during maintenance and service, kilograms;

C_{retire} = Nameplate capacity of the retired unit, kilograms; and

R_{retire} = HFC recovered from the retired unit, kilograms.

(e) Fugitive CO_2 Emissions from Geothermal Facilities. Operators of geothermal electricity generating facilities shall calculate the fugitive CO_2 emissions using one of the following methods:

(1) Calculate the fugitive CO_2 emissions using Equation 40-3:

Equation 40-3

$$CO_2 = 7.14 \times Heat \times 0.001$$

Where:

CO_2	=	CO_2 emissions, tonnes per year;
7.14	=	Default fugitive CO_2 emission factor for geothermal facilities, kg per GJ
Heat	=	Heat taken from geothermal steam and/or fluid, GJ/yr.
0.001	=	Conversion factor from kilograms to tonnes.

(2) Calculate CO_2 emissions using source specific emission factor approved in writing by the Director.

ON.44   Sampling, Analysis, and Measurement Requirements

(a) CO_2, CH_4 and N_2O Emissions from Fuel Combustion. Operators using CEMS to estimate CO_2 emissions from fuel combustion shall comply with the requirements in section ON.23(d). Operators using methods other than CEMS shall comply with the applicable fuel sampling, fuel consumption monitoring, heat content monitoring, carbon content monitoring, and calculation methodologies specified in section ON.25.

(b) CO_2 Emissions from Acid Gas Scrubbing. Operators of electricity generating units that use acid gas scrubbers or add an acid gas reagent to the combustion unit shall measure the amount of limestone or other sorbent used during the reporting year.

(c) CO_2 Emissions from Geothermal Facilities. Operators of geothermal facilities shall measure the heat recovered from geothermal steam. If using source specific emission factor instead of the default factor, the person shall submit a pretest plan to the Director in the first year. The source test procedures in that plan shall be repeated in future year to update the source specific emission factors annually.

ON.45   Procedures for Estimating Missing Data

Whenever a quality-assured value of a required parameter is unavailable (e.g., if a CEMS malfunctions during unit operation or if a required fuel sample is not taken), a substitute data value for the missing parameter shall be used in the calculations.

(a) For all units using CEMS to measure CO_2 emissions, follow the missing data procedures in section ON.26(a)

(b) For all other missing parameters used to calculate GHG emissions, follow the missing data procedures in section ON.26(b).

ON.270   Ferroalloy Production

ON.271   Source Definition

The ferroalloy production source consists of any facility that uses pyrometallurgical techniques to produce any of the following metals: ferrochromium, ferromanganese, ferromolybdenum, ferronickel, ferrosilicon, ferrotitanium, ferrotungsten, ferrovanadium, silicomanganese, or silicon metal.

ON.272   Greenhouse Gas Reporting Requirements

For the purpose of Section 6 of the Regulation the annual emissions data report for ferroalloy production shall include the following information at the facility level calculated in accordance with this method:

(a) Process CO_2 emissions from each electric arc furnace (EAF) used for the production of any ferroalloy listed in ON.271.

(b) Emissions of CO_2, CH_4, and N_2O from stationary combustion units not covered by this method shall follow the requirements of ON.20 (tonnes).

ON.273   Calculation of GHG Emissions

Quantify emissions in accordance with U.S. EPA 40 CFR 98 Subpart K Section 98.113.

ON.274   Sampling, Analysis, and Measurement Requirements

Sampling, analysis and measurement requirements for this source shall be done in accordance with U.S. EPA 40 CFR 98 Subpart K Section 98.114.

ON.275   Procedures for Estimating Missing Data

Missing data requirements for this source shall be estimated in accordance with U.S. EPA 40 CFR 98 Subpart K Section 98.115.

ON.20   General Stationary Combustion

ON.21   Source Definition

General stationary combustion sources are devices that combust solid, liquid, or gaseous fuel for the purpose of producing electricity, generating steam or providing useful heat or energy for industrial, commercial, or institutional use; or providing energy for pollution control; or reducing the volume of waste by removing combustible matter. General stationary combustion sources include boilers, simple and combined cycle combustion turbines, engines, incinerators (including units that combust hazardous waste), process heaters, and any other stationary combustion device that is not specifically addressed under the methods for another source category in the Guideline.

This source definition does not include portable equipment, emergency generators less than 10 MW in nameplate generating capacity, and emergency equipment (including emergency flares) as defined in Section 2 of the Guideline.

ON.22   Greenhouse Gas Reporting Requirements

For the purpose of Section 6 of the Regulation the annual emissions data report for general stationary combustion shall include the following information at the facility level calculated in accordance this method:

(a) Annual greenhouse gas emissions in tonnes, reported as follows:

    (1) Total CO_2 emissions for fossil fuels, reported by fuel type.

    (2) Total CO_2 emissions for biomass, reported by fuel type.

    (3) Total CH_4 emissions, reported by fuel type.

    (4) Total N_2O emissions, reported by fuel type.

(b) Annual fuel consumption:

    (1) For gases, report in units of standard cubic meters.

    (2) For liquids, report in units of kilolitres.

    (3) For non-biomass solids, report in units of tonnes.

    (4) For biomass solid fuels, report in units of bone dry tonnes.

(c) Annual weighted average carbon content of each fuel, if used to compute CO_2 emissions.

(d) Annual weighted average high heat value of each fuel, if used to compute CO_2 emissions.

(e) Annual steam generation in kilograms, for units that burn biomass fuels or municipal solid waste and generate steam.

ON.23   Calculation of CO_2 Emissions

For each fuel, calculate CO_2 mass emissions using one of the four calculation methodologies specified in this section, subject to the restrictions in ON.23(e). If a fuel

or fuels is not listed in all of Tables 20-1 through 20-7; or in Table C-1 or C-2 in U.S. EPA 40 CFR Part 98, Subpart C, then emissions from such fuels do not need to be reported so long as total emissions of these fuels do not exceed 0.5% of total facility emissions.

(a) <u>Calculation Methodology 1</u>. Calculate the annual CO_2 mass emissions for each type of fuel by substituting a fuel-specific default CO_2 emission factor, a default high heat value, and the annual fuel consumption into Equation 20-1:

$$CO_2 = Fuel \times \left(HHV \times EF \right) \times 0.001 \qquad \textbf{Equation 20-1}$$

Where:

CO_2	=	Annual CO_2 mass emissions for the specific fuel type (tonnes).
Fuel	=	Mass or volume of fuel combusted per year (express mass in tonnes for solid fuel, volume in standard cubic meters for gaseous fuel, and volume in kilolitres for liquid fuel).
HHV	=	Default high heat value of the fuel, from Table 20-1 or Table 20-1a (GJ per tonne for solid fuel, GJ per kilolitre for liquid fuel, or GJ per cubic meter for gaseous fuel).
EF	=	Fuel-specific default CO_2 emission factor, from Tables 20-1a, 20-2, 20-3, 20-5, or 20-7, as applicable (kg CO_2/GJ).
(HHV x EF)		instead of using separate HHV and EF values, the person can replace the two values by the use default emission factors from Tables 20-2, 20-3, or 20-5 , as applicable (in units of kg CO_2 per tonne for solid fuel, kg CO_2 per kilolitre for liquid fuel, or kg CO_2 per cubic meter for gaseous fuel)
0.001	=	Conversion factor from kilograms to tonnes.

(b) <u>Calculation Methodology 2</u>. Calculate the annual CO_2 mass emissions using Equation 20-2 and using a default fuel-specific CO_2 emission factor and a high heat value provided by the supplier or measured by the person. For emissions from the combustion of biomass fuels and municipal solid waste, the person may instead elect to use the method shown in Equation 20-3.

(1) For any type of fuel for which an emission factor is provided in Tables 20-1a, 20-2, 20-3, 20-5, or 20-7, as applicable, except biomass fuels and municipal solid waste when the person elects to use the method in ON.23(b)(2), use Equation 20-2:

$$CO_2 = \sum_{p=1}^{n} Fuel_p \times HHV_p \times EF \times 0.001 \qquad \textbf{Equation 20-2}$$

Where:

CO_2	=	Annual CO_2 mass emissions for a specific fuel type (tonnes).
n	=	Number of required heat content measurements for the year as specified in ON.25.
$Fuel_p$	=	Mass or volume of the fuel combusted during the measurement period "p" (express mass in tonnes for solid fuel, volume in

standard cubic meters for gaseous fuel, and volume in kilolitres for liquid fuel).

HHV$_p$ = High heat value of the fuel for the measurement period (GJ per tonne for solid fuel, GJ per kilolitre for liquid fuel, or GJ per cubic meter for gaseous fuel).

EF   = Fuel-specific default CO_2 emission factor, from Tables 20-1a, 20-2, 20-3, 20-5, or 20-7, as applicable (kg CO_2/GJ).

0.001   = Conversion factor from kilograms to tonnes.

(2) For units that combust municipal solid waste and that produce steam, use Equation 20-3. Equation 20-3 of this section may also be used for any solid biomass fuel listed in Table 20-2 of this section provided that steam is generated by the unit.

$$CO_2 = Steam \times B \times EF \times 0.001 \qquad \textbf{Equation 20-3}$$

Where:

CO$_2$ = Annual CO_2 mass emissions from biomass solid fuel or municipal solid waste combustion (tonnes).

Steam   = Total mass of steam generated by biomass solid fuel or municipal solid waste combustion during the reporting year (tonnes steam).

B   = Ratio of the boiler's design rated heat input capacity to its design rated steam output capacity (GJ/tonne steam).

EF   = Default emission factor for biomass solid fuel or municipal solid waste, from Table 20-2 or Table 20-7, as applicable (kg CO_2/GJ).

0.001   = Conversion factor from kilograms to tonnes.

(c) <u>Calculation Methodology 3.</u> Calculate the annual CO_2 mass emissions for each fuel by using measurements of fuel carbon content or molar fraction (for gaseous fuels only), conducted by the person or provided by the fuel supplier, and the quantity of fuel combusted.

(1) For a solid fuel, except for the combustion of municipal solid waste, use Equation 20-4 of this section:

Equation 20-4

$$CO_2 = \sum_{i=1}^{n} Fuel_i \times CC_i \times 3.664$$

Where:

CO$_2$ = Annual CO_2 mass emissions from the combustion of the specific solid fuel (tonnes).

n   = Number of carbon content determinations for the year.

Fuel$_i$ = Mass of the solid fuel combusted in measurement period "i" (tonnes).

CC$_i$ = Carbon content of the solid fuel, from the fuel analysis results for measurement period "i" (per cent by weight, expressed as a decimal fraction, e.g., 95% = 0.95).

3.664   = Ratio of molecular weights, CO_2 to carbon.

(2) For biomass fuels, in units that produce steam, use either Equation 20-4 above or Equation 20-5; for municipal solid waste combustion in units that produce steam, use Equation 20-5:

$$CO_2 = Steam \times B \times EF \times 0.001$$

Equation 20-5

Where:

CO_2	=	Annual CO_2 mass emissions from biomass solid fuel or municipal solid waste combustion (tonnes).
Steam	=	Total mass of steam generated by biomass solid fuel or municipal solid waste combustion during the reporting year (tonnes steam).
B	=	Ratio of the boiler's design rated heat input capacity to its design rated steam output capacity (GJ/tonne steam).
EF	=	Default emission factor for biomass solid fuel or municipal solid waste, from Table 20-2 or 20-7, as applicable (kg CO_2/GJ), adjusted no less often than every third year as provided in ON.25(a)(7)(B).
0.001	=	Conversion factor from kilograms to tonnes.

(3) For a liquid fuel, use Equation 20-6 of this section:

$$CO_2 = \sum_{i=1}^{n} 3.664 \times Fuel_i \times CC_i$$

Equation 20-6

Where:

CO_2	=	Annual CO_2 mass emissions from the combustion of the specific liquid fuel (tonnes).
n	=	Number of required carbon content determinations for the year, as specified in ON.25.
$Fuel_i$	=	Volume of the liquid fuel combusted in measurement period "i" (kilolitres).
CC_i	=	Carbon content of the liquid fuel, from the fuel analysis results for measurement period "i" (tonne C per kilolitre of fuel).
3.664	=	Ratio of molecular weights, CO_2 to carbon.

(4) For a gaseous fuel, use Equation 20-7 of this section:

$$CO_2 = \sum_{i=1}^{n} 3.664 \times Fuel_i \times CC_i \times \frac{MW}{MVC} \times 0.001$$

Equation 20-7

Where:

CO_2	=	Annual CO_2 mass emissions from combustion of the specific gaseous fuel (tonnes).
n	=	Number of required carbon content and molecular weight determinations for the year, as specified in ON.25.
$Fuel_i$	=	Volume of the gaseous fuel combusted in period "i" (a day or month, as applicable) (Rm^3) at reference temperature and pressure conditions as used by the facility. If a mass flow meter is used,

measure the fuel combusted in period "i"in kg and replace the term "MW/MVC" with "1"

CC_i = Average carbon content of the gaseous fuel, from the fuel analysis results for the period "i" (day or month, as applicable) (kg C per kg of fuel).

MW = Molecular weight of the gaseous fuel, from fuel analysis (kg/kg-mole).

MVC = Molar volume conversion factor at the same reference conditions as the above $Fuel_i$ (Rm3/kg-mole).

= 8.3145 * [273.16 + reference temperature in °C] / [reference pressure in kilopascal]
(which is 23.6 Sm^3 per kg-mole for STP of 15°C and 1 atmosphere).

3.664 = Ratio of molecular weights, CO_2 to carbon.

0.001 = Conversion factor from kg to tonnes.

(d) <u>Calculation Methodology 4.</u> Calculate the annual CO_2 mass emissions from all fuels combusted in a unit, by using data from CEMS as specified in (d)(1) through (d)(7). This methodology requires a CO_2 concentration monitor and a stack gas volumetric flow monitor, except as otherwise specified in (d)(3) of this section.

(1) For a facility that operates CEMS in response to federal or provincial regulation, use CO_2 or O_2 concentrations and flue gas flow measurements to determine hourly CO_2 mass emissions using methodologies provided in Protocols And Performance Specifications For Continuous Monitoring Of Gaseous Emissions From Thermal Power Generation (Report EPS 1/PG/7 (Revised) December 2005) (or by other relevant document, if superseded). .

(2) The person shall report CO_2 emissions for the reporting year in tonnes based on the sum of hourly CO_2 mass emissions over the year, converted to tonnes.

(3) An oxygen (O_2) concentration monitor may be used in lieu of a CO_2 concentration monitor in a CEMS installed before January 1, 2012, to determine the hourly CO_2 concentrations, if the effluent gas stream monitored by the CEMS consists solely of combustion products (i.e., no process CO_2 emissions or CO_2 emissions from acid gas control are mixed with the combustion products) and if only the following fuels are combusted in the unit: coal, petroleum coke, oil, natural gas, propane, butane, wood bark, or wood residue.

(A) If the unit combusts waste derived fuels (as defined in Section 2 of the Guideline), emissions calculations shall not be based on O_2 concentrations.

(B) If the facility that combusts biomass fuels uses O_2 concentrations to calculate CO_2 concentrations, annual source testing must demonstrate that calculated CO_2 concentrations when compared to measured CO_2 concentrations meet the Relative Accuracy Test Audit (RATA) requirements in Protocols And Performance Specifications For Continuous Monitoring Of Gaseous Emissions From Thermal Power Generation

(Report EPS 1/PG/7 (Revised) December 2005)(or by other relevant document, if superseded).

(4) If both biomass fuel (including fuels that are partially biomass) and fossil fuel are combusted during the year, determine and report the biogenic CO_2 mass emissions separately, as described in paragraph (f) of this section.

(5) Notwithstanding Section 23(d)(2) of the Guideline, for any units for which CO_2 emissions are reported using CEMS data, the person is not required to separately report process emissions from combustion emissions for that unit and is also not required to report emissions separately for different fossil fuels for that unit when only fossil fuels are co-fired. In this circumstance, the person shall still report fuel use by fuel type as otherwise required.

(6) If a facility is subject to requirements for continuous monitoring of gaseous emissions, and the person chooses to add devices to an existing CEMS for the purpose of measuring CO_2 concentrations or flue gas flow, the person shall select and operate the added devices pursuant to the appropriate requirements for the facility as applicable in Canada.

(7) If a facility does not have a CEMS and the person chooses to add one in order to measure CO_2 concentrations, the person shall select and operate the CEMS pursuant to the appropriate requirements or equivalent requirements as applicable in Canada. Operators who add CEMS under this paragraph are subject to the specifications in paragraphs (d)(1) through (d)(5), if applicable.

(e) <u>Use of the Four CO_2 Calculation Methodologies</u>. The use of the four CO_2 emissions calculation methodologies described in paragraphs (a) through (d) of this section is subject to the following requirements and restrictions:

(1) <u>Calculation Methodology 1 (Equation 20-1)</u>.

(A) May be used by a facility that is not subject to the Regulation for any type of fuel for which a default high heat value for the fuel (Table 20-1 or 20-1a) and a default CO_2 emission factor (Table 20-1a, 20-2, 20-3, or 20-5, as applicable) is specified.

(B) May be used for a facility for the combustion of natural gas with a high heat value between 36.3 and 40.98 MJ per cubic meter, and for the combustion of any of the fuels listed in Table 20-1a.

(C) May be used for a facility for the combustion of municipal solid waste, in a unit that does not generate steam.

(D) May be used for the combustion of biomass listed in Table 20-2, unless it is specifically addressed under the provisions for another source category (e.g., spent pulping liquor in pulp and paper) in the Guideline.

(E) May not be used at a facility emitting at any level for a fuel for which the person routinely perform fuel sampling and analysis for the fuel high heat value or can obtain the results of fuel sampling and analysis for the fuel high heat value from the fuel supplier at the minimum frequency specified

in ON.25(a), or at a greater frequency. In such cases, Calculation Methodologies 2, 3 or 4 shall be used for those fuels.

(2) Calculation Methodology 2 (Equations 20-2 and 20-3).

    (A) May not be used by a facility that is subject to the Regulation, except as specified in paragraphs (e)(2)(B) through (D) of this section. Otherwise, Calculation Methodology 2 may be used for any type of fuel combusted for which a default CO_2 emission factor for the fuel is specified in Tables 20-1a, 20-2, 20-3, 20-5, or 20-7, as applicable.

    (B) Calculation Methodology 2 may be used for the combustion of natural gas with a high heat value between 36.3 and 40.98 MJ per cubic meter at a facility emitting at any level. Notwithstanding the provisions in paragraph (e)(1) of this section, Calculation Methodology 2 or 3 or 4 shall be used by the person for combustion in any unit with a rated heat input capacity greater than 264 GJ/hr (250mmBtu/hr) and that has operated for more than 1,000 hours in any of the past three years, when the fuel is natural gas with a high heat value between 36.3 and 40.98 MJ per cubic meter.

    (C) Calculation Methodology 2 may be used at a facility emitting at any level for the combustion of any of the fuels listed in Table 20-1a, and for biomass.

    (D) Equation 20-3 may be used for the combustion of municipal solid waste only at facilities that are not subject to the Regulation.

(3) Calculation Methodology 3 (Equations 20-4 through 20-7) may be used for the combustion of any type of fuel, except as specified in paragraph (e)(3)(A) through (E) of this section.

    (A) Notwithstanding the provisions in paragraph (e)(1) and (e)(2) of this section, Calculation Methodology 3 or 4 shall be used at a facility subject to the Regulation for all combustion in any unit with a rated heat input capacity greater than 264 GJ/hr (250mmBtu/hr) and that has operated for more than 1,000 hours in any of the past three years, except when the fuel is natural gas with a high heat value between 36.3 and 40.98 MJ per cubic meter, the fuel is listed in Table 20-1a, or the fuel is biomass.

    (B) Must be used for all other combustion at a facility subject to the Regulation, except for combustion of fuels for which Calculation Methodology 1 or 2 is permitted, as described in paragraphs (e)(1) and (e)(2) of this section.

    (C) May not be used when the use of Calculation Methodology 4 is required.

    (D) Equation 20-4 may not be used for the calculation of emissions from combustion of municipal solid waste.

    (E) Equation 20-5 may be used for the combustion of municipal solid waste at a facility emitting at any level; but, it must be used for the combustion of municipal solid waste if the facility is subject to the Regulation, unless Calculation Methodology 4 is required.

(4) Calculation Methodology 4 may be used for a unit combusting any type of fuel. Notwithstanding the provisions in paragraphs (e)(1) through (3) of this section, Calculation Methodology 4 must be used for a combustion unit with a CEMS that includes a stack gas volumetric flow rate monitor and a CO_2 concentration monitor that is required by any federal or provincial regulation.

(5) The person may elect to use Calculation Methodologies 3 or 4 for one or more of the fuels combusted in a unit. For example, if a unit combusts natural gas and distillate fuel oil, the person may elect to use Calculation Methodology 1 for natural gas and Calculation Methodology 2 for the fuel oil, even though Calculation Methodology 1 could have been used for both fuels. However, for units that use Calculation Methodology 4, CO_2 emissions from the combustion of all fuels shall be based solely on CEMS measurements.

(f) CO_2 emissions from combustion of mixtures of biomass or biomass fuel and fossil fuel. Use the procedures of this paragraph (f) to estimate biogenic CO_2 emissions from units that combust a combination of biomass and fossil fuels, including combustion of waste-derived fuels (e.g., municipal solid waste or tires) that are partially biomass. .

(1) If CEMS are not used to measure CO_2 and the facility combusts biomass fuels that do not include waste-derived fuels (e.g., municipal solid waste and tires), use Methods 1, 2, or 3, as applicable, to calculate the annual biogenic CO_2 mass emissions from the combustion of biomass fuels. Determine the mass of biomass combusted using either company records, or, for premixed fuels that contain biomass and fossil fuels (e.g., mixtures containing biodiesel), use best available information to determine the mass of biomass fuels and document the procedure.

(2) If a CEMS is used to measure CO_2 (or O_2 as a surrogate) and the facility combusts biomass fuels that do not include waste-derived fuels (as defined in the Guideline), use Calculation Methodologies 1, 2, or 3 to calculate the annual CO_2 mass emissions from the combustion of fossil fuels. Calculate biomass fuel emissions by subtracting the fossil fuel-related emissions from the total CO_2 emissions determined from the CEMS-based methodology.

(3) If the person that combusts fuels or fuel mixtures for which the biomass fraction is unknown or cannot be documented (for example, municipal solid waste or tire-derived fuel), or if the person combusts a biomass fuel for which a CO_2 emission factor is not provided in Table 20-2, use the following to estimate biogenic CO_2 emissions:

   (A) Use Calculation Methodologies 1, 2, 3, or 4 to calculate the total annual CO_2 mass emissions, as applicable.

   (B) Determine the biogenic portion of the CO_2 emissions using ASTM D6866, as specified in this paragraph. This procedure is not required for fuels that contain less than 5 per cent biomass by weight or for waste-derived fuels that are less than 30 per cent by weight of total fuels combusted in the year for which emissions are being reported, except where the person wishes to report a biomass fuel fraction of CO_2 emissions.

(C) The person shall conduct ASTM D6866 analysis on a representative fuel or exhaust gas sample at least every three months. The exhaust gas samples shall be collected over at least 24 consecutive hours following the standard practice specified by ASTM D7459. If municipal solid waste is combusted, the ASTM D6866 analysis must be performed on the exhaust gas stream.

(D) The person shall divide total CO_2 emissions between biomass fuel emissions and non-biomass fuel emissions using the average proportions of the samples analyzed for the year for which emissions are being reported.

(E) If there is a common fuel source to multiple units at the facility, the person may elect to conduct ASTM D6866 testing for only one of the units sharing the common fuel source.

(4) If Equation 20-1 of this section is selected to calculate the annual biogenic mass emissions for wood, wood waste, or other solid biomass-derived fuel, Equation 20-8 of this section may be used to quantify biogenic fuel consumption, provided that all of the required input parameters are accurately quantified. Similar equations and calculation methodologies based on steam generation and boiler efficiency may be used, provided that they are documented.

$$(Fuel)_p = \frac{[H * S] - (HI)_{nb}}{(HHV)_{bio} \, (Eff)_{bio}}$$

Equation 20-8

Where:

$(Fuel)_p$ = Quantity of biomass consumed during the measurement period "p" (tonnes/year or tonnes/month, as applicable).

H = Average enthalpy of the boiler steam for the measurement period (GJ/tonne).

S = Total boiler steam production for the measurement period (tonnes/month or tonnes/year, as applicable).

$(HI)_{nb}$ = Heat input from co-fired fossil fuels and non-biomass-derived fuels for the measurement period, based on company records of fuel usage and default or measured HHV values (GJ/month or GJ/year, as applicable).

$(HHV)_{bio}$ = Default or measured high heat value of the biomass fuel (GJ/tonne).

$(Eff)_{bio}$ = Per cent efficiency of biomass-to-energy conversion, expressed as a decimal fraction.

(g) Calculation of CO_2 from sorbent.

(1) When a unit is a fluidized bed boiler, is equipped with a wet flue gas desulphurization system, or uses other acid gas emission controls with sorbent injection, use Equation 20-9 of this section to calculate the CO_2 emissions from the sorbent, if those CO_2 emissions are not monitored by CEMS:

$$CO_2 = S * R * \left(\frac{MW_{CO2}}{MW_S} \right) \qquad \text{Equation 20-9}$$

Where:

CO_2	=	CO_2 emitted from sorbent for the reporting year (tonnes).
S	=	Limestone or other sorbent used in the reporting year, from company records (tonnes).
R	=	1.00, the calcium-to-sulphur stoichiometric ratio.
MW_{CO2}	=	Molecular weight of carbon dioxide.
MW_S	=	Molecular weight of sorbent.

(2) The annual CO_2 mass emissions for the unit shall be the sum of the CO_2 emissions from the combustion process and the CO_2 emissions from the sorbent.

ON.24   Calculation of CH_4 and N_2O Emissions

Calculate the annual CH_4 and N_2O mass emissions from stationary fuel combustion sources using the procedures in paragraph (a), (b), or (c), as appropriate.

The person is not required to calculate the annual CH_4 and N_2O emissions for fuels that are not listed in Tables 20-2, 20-3, 20-4 and 20-6. However, any person may use engineering estimates to calculate the annual CH_4 and N_2O emissions for fuels that are not listed in Tables 20-2, 20-3, 20-4 and 20-6.

(a) If the high heat value of the fuel is not measured for CO_2 estimation, calculate CH_4 and N_2O emissions using Equation 20-10 for all fuels except coal. For coal, use Equation 20-11:

$$CH_4 \text{ or } N_2O = Fuel \times HHV_D \times EF \times 0.000001 \qquad \textbf{Equation 20-10}$$

$$CH_4 \text{ or } N_2O = Fuel \times EF_c \times 0.001 \qquad \textbf{Equation 20-11}$$

Where:

CH_4 or N_2O	=	Combustion emissions from specific fuel type, tonnes CH_4 or N_2O per year.
Fuel	=	Mass or volume of fuel combusted per year (express mass in tonnes for solid fuel, volume in standard cubic meters for gaseous fuel, and volume in kilolitres for liquid fuel).
HHV_D	=	Default high heat value specified by fuel type provided in Table 20-1 or 20-1a, (GJ per tonne for solid fuel, GJ per kilolitre for liquid fuel, or GJ per cubic meter for gaseous fuel).
EF	=	Default CH_4 or N_2O emission factor provided in Tables 20-2 or 20-4, as applicable, grams CH_4 or N_2O per GJ. The person may also

use equipment specific factors from U.S. EPA AP42 for the
specific equipment as appropriate.

EF_c = Default CH_4 or N_2O emission factor for coal provided in Table 20-
6 (grams CH_4 or N_2O per kg of coal). The person may also use
equipment specific factors from U.S. EPA AP42 for the specific
equipment as appropriate.

0.000001 = Factor to convert grams to tonnes in Equation 20-8.

0.001 = Factor to convert g/kg to tonne/tonne in Equation 20-9.

(b) If the high heat value of the fuel is measured or provided by the fuel supplier for CO_2
estimation, calculate CH_4 and N_2O emissions using Equation 20-12 for all fuels
except coal. For coal, use Equation 20-13:

$$CH_4 \; or \; N_2O = \sum_{p=1}^{n} Fuel_p \times HHV_p \times EF \times 0.000001$$ **Equation 20-12**

$$CH_4 \; or \; N_2O = \sum_{p=1}^{n} Fuel_p \times EF_c \times 0.000001$$ **Equation 20-13**

Where:

CH_4 or N_2O = CH_4 or N_2O emissions from a specific fuel type, tonnes CH_4 or
N_2O per year.

$Fuel_p$ = Mass or volume of the fuel combusted during the measurement
period "p" (express mass in tonnes for solid fuel, volume in
standard cubic meters for gaseous fuel, and volume in kilolitres for
liquid fuel).

HHV_p = High heat value measured directly or provided by the fuel supplier
for the measurement period, p, specified by fuel type (GJ per
tonne for solid fuel, GJ per kilolitre for liquid fuel, or GJ per cubic
meter for gaseous fuel).

EF = Default CH_4 or N_2O emission factor provided in Tables 20-2 or 20-
4, as applicable, grams CH_4 or N_2O per GJ. The person may also
use equipment specific factors from U.S. EPA AP42 for the
specific equipment as appropriate.

EF_c = CH_4 or N_2O emission factor for coal, either measured directly or
provided by the fuel supplier, grams CH_4 or N_2O per tonne of coal

0.000001 = Factor to convert grams to tonnes.

(c) For biomass and municipal solid waste combustion where Equation 20-3 or 20-5 are
used to calculate CO_2 emissions, use Equation 20-14 of this section to estimate CH_4
and N2O emissions:

$$CH_4 \; or \; N_2O = Steam \times B \times EF \times 0.000001$$ **Equation 20-14**

Where:

CH_4 or N_2O = Annual CH_4 or N_2O emissions from the combustion of a
municipal solid waste (tonnes).

Steam	=	Total mass of steam generated by municipal solid waste combustion during the reporting year (tonnes steam).
B	=	Ratio of the boiler's design rated heat input capacity to its design rated steam output (GJ/tonne steam).
EF	=	Fuel-specific emission factor for CH_4 or N_2O, from Tables 20-2, 20-4 or 20-6, as applicable (grams CH_4 or N_2O per GJ).
0.000001	=	Conversion factor from grams to tonnes.

(d) Use Equation 20-15 of this section for units that use Calculation Methodology 4 and for which heat input is monitored on a year round basis.

$$CH_4 \ or \ N_2O = 0.001 * (HI)_A * EF \qquad \textbf{Equation 20-15}$$

Where:

CH_4 or N_2O	=	Annual CH_4 or N_2O emissions from the combustion of a particular type of fuel (tonnes).
$(HI)_A$	=	Cumulative annual heat input from the fuel (GJ), derived from the electronic data reports or estimated from the best available information (e.g., fuel feed rate measurements, fuel heating values, engineering analysis).
EF	=	Fuel-specific emission factor for CH_4 or N_2O, from Tables 20-2, 20-4 or 20-6, as applicable (grams CH_4 or N_2O per GJ).
0.001	=	Conversion factor from kg to tonnes.

(1) If only one type of fuel is combusted during normal operation, substitute the cumulative annual heat input from combustion of the fuel into Equation 20-15 of this section to calculate the annual CH_4 or N_2O emissions.

(2) If more than one type of fuel listed is combusted during normal operation, use Equation 20-15 of this section separately for each type of fuel.

(e) When multiple fuels are combusted during the reporting year, sum the fuel-specific results from Equations 20-8, 20-9, 20-10, or 20-11 of this section (as applicable) to obtain the total annual CH_4 and N_2O emissions, in tonnes.

(f) The person may elect to calculate CH_4 or N_2O emissions using source-specific emission factors derived from source tests conducted annually. The person shall submit a pretest plan to the Director in the first year of reporting. The source test procedures in that plan shall be repeated in each future year to update the source specific emission factor annually.

(g) Use of the four CH_4 and N_2O Calculation Methodologies. Use of the four CH_4 and N_2O emissions calculation methodologies described in paragraphs (a) through (d) of this section is subject to the following requirements and restrictions:

(1) ON.24(a) may not be used by a facility that is subject to the Regulation, except for stationary combustion units that combust natural gas with a higher heating

value between 36.3 and 40.98 MJ per cubic meter. Otherwise, ON.24(a) may be used for any type of fuel for which a default CH_4 or N_2O emission factor (Tables 20-2, 20-4, 20-6, 20-7) and a default higher heat value (Table 20-1 and 20-1a) is specified.

(2) ON.24(b) may be used for a unit of any size combusting any type of fuel.

(3) ON.24(c) may only be used for biomass or municipal solid waste combustion. ON.24(c) must be used instead of ON.24(a) for any unit combusting municipal solid waste that generates steam.

(4) ON.24(d) may be used for a unit of any size combusting any type of fuel, and must be used for any units for which Calculation Methodology 4 is used to estimate CO_2 emissions and heat input is monitored on a year round basis.

ON.25   Sampling, Analysis, and Measurement Requirements

(a) Fuel Sampling Requirements. Fuel sampling must be conducted or fuel sampling results must be received from the fuel supplier at the minimum frequency specified in paragraphs (a)(1) through (a)(7) of this section, subject to the requirements of ON.23(e) and ON.24(g). All fuel samples shall be taken at a location in the fuel handling system that provides a representative of the fuel combusted.

(1) Once for each new fuel shipment or delivery for coal.

(2) Once for each new fuel shipment or delivery of fuels, or quarterly for each of the fuels listed in Table 20-1a (when required).

(3) Semiannually for natural gas (when required).

(4) Quarterly for liquid fuels and fossil fuel derived gaseous fuels other than fuels listed in Table 20-1a.

(5) Quarterly for gases derived from biomass including landfill gas and biogas from wastewater treatment or agricultural processes.

(6) For gaseous fuels other than natural gas, gases derived from biomass, and biogas, daily sampling and analysis to determine the carbon content and molecular weight of the fuel is required if the necessary equipment is in place to make these measurements. For 2011 calendar year emissions only, if the necessary equipment is not in place to make the measurements, weekly sampling and analysis shall be performed. If on-line instrumentation is to be used, the equipment necessary to perform daily sampling and analysis of carbon content and molecular weight must determine fuel carbon content accurate to ± 5 per cent.

(7) Monthly for solid fuels other than coal and waste-derived fuels (including municipal solid waste), as specified below:

   (A) The monthly solid fuel sample shall be a composite sample of weekly samples.

   (B) The solid fuel shall be sampled at a location after all fuel treatment operations but before fuel mixing and the samples shall be representative of

the fuel chemical and physical characteristics immediately prior to combustion.

    (C) Each weekly sub-sample shall be collected at a time (day and hour) of the week when the fuel consumption rate is representative and unbiased.

    (D) Four weekly samples (or a sample collected during each week of operation during the month) of equal mass shall be combined to form the monthly composite sample.

    (E) The monthly composite sample shall be homogenized and well mixed prior to withdrawal of a sample for analysis.

    (F) One in twelve composite samples shall be randomly selected for additional analysis of its discrete constituent samples. This information will be used to monitor the homogeneity of the composite.

(8) For biomass fuels and waste-derived fuels (including municipal solid waste), the following may apply in lieu of ON.25(a)(6):

    (A) If CO_2 emissions are calculated using Equation 20-2 in ON.23(b)(1) or Equation 20-4 in ON.23(c)(1), the source-specific high heat value or carbon content is determined annually.

    (B) If CO_2 emissions are calculated using Equation 20-5 in ON.23(c)(2) (biomass fuels and municipal solid waste only), the person shall adjust the emission factor, in kg CO_2/MJ not less frequently than every third year, through a stack test measurement of CO_2 and use of the applicable ASME Performance Test Code to determine heat input from all heat outputs, including the steam, flue gases, ash and losses.

(b) Fuel Consumption Monitoring Requirements.

(1) Facilities may determine fuel consumption on the basis of direct measurement or recorded fuel purchase or sales invoices measuring any stock change (measured in MJ, litres, million standard cubic meters, tonnes or bone dry tonnes) using the Equation 20-16:

Fuel Consumption in the Report Year = Total Fuel Purchases – Total Fuel Sales + Amount Stored at Beginning of Year – Amount Stored at Year End

Equation 20-16

(2) Fuel consumption measured in MJ values shall be converted to the required metrics of mass or volume using heat content values that are either provided by the supplier, measured by the facility, or provided in Table 20-1.

(3) All oil and gas flow meters (except for gas billing meters) shall be calibrated prior to the first year for which GHG emissions are reported under the Regulation, using an applicable flow meter test method listed in Section 5 of the Guideline or the calibration procedures specified by the flow meter manufacturer. Fuel flow meters shall be recalibrated either annually or at the minimum frequency specified by the manufacturer.

(4) For fuel oil, tank drop measurements may also be used.

(5) Fuel flow meters that measure mass flow rates may be used for liquid fuels, provided that the fuel density is used to convert the readings to volumetric flow rates. The density shall be measured at the same frequency as the carbon content, using ASTM D1298 - Standard Test Method for Density, Relative Density (Specific Gravity), or API Gravity of Crude Petroleum and Liquid Petroleum Products by Hydrometer Method.

(6) Facilities using Calculation Methodologies 1 or 2 for CO_2 emissions may use the following default density values for fuel oil, in lieu of using the ASTM method in paragraph (b)(5) of this section: 0.81 kg/litre for No. 1 oil; 0.86 kg/litre for No. 2 oil; 0.97 kg/litre for No. 6 oil. These default densities may not be used for facilities using Calculation Methodology 3.

(c) Fuel Heat Content Monitoring Requirements. High heat values shall be based on the results of fuel sampling and analysis received from the fuel supplier or determined by the person, in either case using an applicable analytical method listed by the Regulation.

(1) For gases, use ASTM D1826, ASTM D3588, ASTM D4891, GPA Standard 2261-2000 or GPA Standard 2172-96. The person may alternatively elect to use on-line instrumentation that determines heating value accurate to within ± 5.0 per cent. Where existing on-line instrumentation provides only low heat value, the person shall convert the value to high heat value as follows:

$$HHV = LHV \times CF$$ **Equation 20-17**

Where:

HHV = fuel or fuel mixture high heat value (MJ/Sm^3).
LHV = fuel or fuel mixture low heat value (MJ/Sm^3).
CF = conversion factor.

For natural gas, a CF of 1.11 shall be used. For refinery fuel gas and mixtures of refinery fuel gas, a weekly average fuel system-specific CF shall be derived as follows:

 (A) By concurrent LHV instrumentation measurements and HHV determined by on-line instrumentation or laboratory analysis as part of the daily carbon content determination; or,

 (B) By the HHV/LHV ratio obtained from the laboratory analysis of the daily samples.

(2) For middle distillates and oil, or liquid waste-derived fuels, use ASTM D240, or ASTM D4809.

(3) For solid biomass-derived fuels, use ASTM D5865.

(4) For waste-derived fuels, use ASTM D5865 or ASTM D5468. Operators who combust waste-derived fuels that are not pure biomass fuels shall determine the

biomass fuel portion of CO_2 emissions using the method specified in ON.23(f), if applicable

(5) Use Equation 20-18 to calculate the weighted annual average heat content of the fuel, if the measured heat content is used to calculate CO_2 emissions.

$$(HHV)_{annual} = \frac{\sum\limits_{p=1}^{n}(HHV)_p * (Fuel)_p}{\sum\limits_{p=1}^{n}(Fuel)_p}$$ **Equation 20-18**

Where:

$(HHV)_{annual}$ = Weighted annual average high heat value of the fuel (GJ per tonne for solid fuel, GJ per kilolitre for liquid fuel, or GJ per cubic meter for gaseous fuel).

$(HHV)_p$ = High heat value of the fuel, for measurement period "p" (GJ per tonne for solid fuel, GJ per kilolitre for liquid fuel, or GJ per cubic meter for gaseous fuel).

$(Fuel)_p$ = Mass or volume of the fuel combusted during measurement period "p" (express mass in tonnes for solid fuel, volume in standard cubic meters for gaseous fuel, and volume in kilolitres for liquid fuel).

n = Number of measurement periods in the year that fuel is burned in the unit.

(d) Fuel Carbon Content Monitoring Requirements. Fuel carbon content and either molecular weight or molar fraction for gaseous fuels shall be based on the results of fuel sampling and analysis received from the fuel supplier or determined by the person, in either case using an applicable analytical method listed by regulation.

(1) For coal and coke, solid biomass fuels, and waste-derived fuels; use ASTM 5373.

(2) For liquid fuels, use the following ASTM methods: For petroleum-based liquid fuels and liquid waste-derived fuels, use ASTM D5291- Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants, ultimate analysis of oil or computations based on ASTM D3238 and either ASTM D2502 or ASTM D2503.

(3) For gaseous fuels, use ASTM D1945 or ASTM D1946.

(4) Use Equation 20-19 to calculate the weighted annual average carbon content of the fuel, if the measured carbon content is used to calculate CO_2 emissions.

$$(CC)_{annual} = \frac{\sum\limits_{p=1}^{n}(CC)_p * (Fuel)_p}{\sum\limits_{p=1}^{n}(Fuel)_p}$$ **Equation 20-19**

Where:

(CC)$_{annual}$ = Weighted annual average carbon content of the fuel (per cent C by weight for solid fuel, tonne C per kilolitre for liquid fuel, or kg C per kg fuel for gaseous fuel).

(CC)$_p$ = Carbon content of the fuel, for measurement period "p" (per cent C by weight for solid fuel, tonne C per kilolitre for liquid fuel, or kg C per kg fuel for gaseous fuel).

(Fuel)$_p$ = Mass or volume of the fuel combusted during measurement period "p" (express mass in tonnes for solid fuel, volume in standard cubic meters for gaseous fuel, and volume in kilolitres for liquid fuel).

n = Number of measurement periods in the years that fuel is burned in the unit.

(e) Fuel Analytical Data Capture. When the applicable emissions estimation methodologies in ON.23 and ON.24 require periodic collection of fuel analytical data for an emissions source, the person shall demonstrate every reasonable effort to obtain a fuel analytical data capture rate of 100 per cent for each report year.

(1) If the person is unable to obtain fuel analytical data such that more than 20 per cent of emissions from a source cannot be directly accounted for, the emissions from that source shall be considered unverifiable for the report year.

(2) If the fuel analytical data capture rate is at least 80 per cent but less than 100 per cent for any emissions source identified in ON.23 and ON.24, the person shall use the methods in ON.26(b) to substitute for the missing values for the period of missing data.

ON.26   Procedures for Estimating Missing Data.

Whenever a quality-assured value of a required parameter is unavailable (e.g., if a CEMS malfunctions during unit operation or if a required fuel sample is not taken), a substitute data value for the missing parameter calculated in accordance with this section shall be used in the calculations.

(a) For all units subject to the requirements of ON.20 that monitor and report emissions using a CEMS, the missing data backfilling procedures in Protocols And Performance Specifications For Continuous Monitoring Of Gaseous Emissions From Thermal Power Generation (Report EPS 1/PG/7 (Revised) December 2005) (or by other relevant document, if superseded) shall be followed for CO_2 concentration, stack gas flow rate, fuel flow rate, high heating value, and fuel carbon content.

(b) For units that use Calculation Methodologies 1, 2, 3, or 4, perform missing data substitution as follows for each parameter:

(1) For each missing value of the high heating value, carbon content, or molecular weight of the fuel, substitute the arithmetic average of the quality-assured values of that parameter immediately preceding and immediately following the missing data incident. If the "after" value has not been obtained by the time that the GHG emissions must be calculated, the person may use the "before" value for missing

data substitution or the best available estimate of the parameter, based on all available process data (e.g., electrical load, steam production, operating hours). If, for a particular parameter, no quality-assured data is available prior to the missing data incident, the substitute data value shall be the first quality-assured value obtained after the missing data period.

(2) For missing records of CO_2 concentration, stack gas flow rate, per cent moisture, fuel usage, and sorbent usage, the substitute data value shall be the best available estimate of the parameter, based on all available process data (e.g., electrical load, steam production, operating hours, etc.). The person must document and retain records of the procedures used for all such estimates.

Table 20-1: Default High Heat Value by Fuel Type

Liquid Fuels	High Heat Value (GJ/kl)
Asphalt & Road Oil	44.46
Aviation Gasoline	33.52
Diesel	38.3
Aviation Turbo Fuel	37.4
Kerosene	37.68
Propane	25.31
Ethane	17.22
Butane	28.44
Lubricants	39.16
Motor Gasoline - Off-Road	35
Light Fuel Oil	38.8
Residual Fuel Oil (#5 & 6)	42.5
Crude Oil	38.32
Naphtha	35.17
Petrochemical Feedstocks	35.17
Petroleum Coke - Refinery Use	46.35
Petroleum Coke – Upgrader Use	40.57
Ethanol (100%)	21.04
Biodiesel (100%)	32.06
Rendered Animal Fat	31.05
Vegetable Oil	30.05
Solid Fuels	**High Heat Value (GJ/tonne)**
Anthracite Coal	27.7
Bituminous Coal	26.33
Foreign Bituminous Coal	29.82
Sub-Bituminous Coal	19.15
Lignite	15
Coal Coke	28.83
Solid Wood Waste	18

Spent Pulping Liquor	14
Municipal Solid Waste	11.57
Tires	31.18
Agricultural byproducts	8.6
Solid byproducts	26.93
Gaseous Fuels	**High Heat Value (GJ/m3)**
Natural Gas	0.03832
Coke Oven Gas	0.01914
Still Gas – Refineries	0.03608
Still Gas – Upgraders	0.04324
Landfill Gas (captured methane)	0.0359
Biogas (captured methane)	0.0281

[1]The default high heat value for "propane" is only for the pure gas species. For the product commercially sold as propane, the value for liquefied petroleum gas in Table 20-1a should be used instead.

Table 20-1a
Fuels for which Calculation Methodologies 1 or 2 may be used at a facility emitting at any level

Fuel Type	Default High Heat Value	Default CO_2 Emission Factor
Petroleum Products	**GJ/kilolitre**	**kg CO_2 /GJ**
Distillate Fuel Oil No. 1	38.78	69.37
Distillate Fuel Oil No. 2	38.50	70.05
Distillate Fuel Oil No. 4	40.73	71.07
Kerosene	37.68	67.25
Liquefied petroleum gases (LPG)	25.66	59.65
Propane (pure, not mixtures of LPGs)[1]	25.31	59.66
Propylene	25.39	62.46
Ethane	17.22	56.68
Ethylene	27.90	63.86
Isobutane	27.06	61.48
Isobutylene	28.73	64.16
Butane	28.44	60.83
Butylene	28.73	64.15
Natural Gasoline	30.69	63.29
Motor Gasoline	34.87	65.40
Aviation Gasoline	33.52	69.87
Kerosene-Type Jet Fuel	37.66	68.40

[1]The default factors for "propane" are only for the pure gas species. For the product commercially sold as propane, the values for LPG should be used instead.

Table 20-2: Default Emission Factors by Fuel Type

Liquid Fuels	CO_2 Emission Factor (kg /kL)	CO_2 Emission Factor (kg /GJ)	CH_4 Emission Factor (g/L)	CH_4 Emission Factor (g/GJ)	N_2O Emission Factor (g/L)	N_2O Emission Factor (g/GJ)
Aviation Gasoline	0.002342	69.87	2.2	65.63	0.23	6.862
Diesel	0.002663	69.53	0.133	3.473	0.4	10.44
Aviation Turbo Fuel	0.002534	67.75	0.08	2.139	0.23	6.150
Kerosene						

- Electric Utilities	0.002534	67.25	0.006	0.159	0.031	0.823
- Industrial	0.002.534	67.25	0.006	0.159	0.031	0.823
- Producer Consumption	0.002534	67.25	0.006	0.159	0.031	0.823
- Forestry, Construction, and Commercial/Institutional	0.002534	67.25	0.026	0.69	0.031	0.823
Propane						
- Residential	0.00151	59.66	0.027	1.067	0.108	4.267
- All other uses	0.00151	59.66	0.024	0.948	0.108	4.267
Ethane	0.000976	56.68	N/A	N/A	N/A	N/A
Butane	0.00173	60.83	0.024	0.844	0.108	3.797
Lubricants	0.00141	36.01	N/A	N/A	N/A	N/A
Motor Gasoline – Off-Road	0.002289	65.40	2.7	77.14	0.05	1.429
Light Fuel Oil						
- Electric Utilities	0.002725	70.23	0.18	4.639	0.031	0.799
- Industrial	0.002725	70.23	0.006	0.155	0.031	0.799
- Producer Consumption	0.002643	68.12	0.006	0.155	0.031	0.799
- Forestry, Construction, and Commercial/Institutional	0.002725	70.23	0.026	0.67	0.031	0.799
Residual Fuel Oil (#5 & 6)						
- Electric Utilities	0.003124	73.51	0.034	0.800	0.064	1.506
- Industrial	0.003124	73.51	0.12	2.824	0.064	1.506
- Producer Consumption	0.003158	74.31	0.12	2.824	0.064	1.506
- Forestry, Construction, and Commercial/Institutional	0.003124	73.51	0.057	1.341	0.064	1.820
Naphtha	0.000625	17.77	N/A	N/A	N/A	N/A
Petrochemical Feedstocks	0.0005	14.22	N/A	N/A	N/A	N/A
Petroleum Coke - Refinery Use	0.003826	82.55	0.12	2.589	0.0265	0.572
Petroleum Coke - Upgrader Use	0.003494	86.12	0.12	2.958	0.0231	0.569

Biomass	CO_2 Emission Factor (kg/tonne)	CO_2 Emission Factor (kg /GJ)	CH_4 Emission Factor (g/kg)	CH_4 Emission Factor (g/GJ)	N_2O Emission Factor (g/kg)	N_2O Emission Factor (g/GJ)
Landfill Gas	0.002989	83.3	0.6	16.7	0.06	1.671
Wood Waste (Env. Canada)[1]	0.00095	52.8	0.05	2.778	0.02	1.111
Wood Waste (U.S. EPA)[2]	0.001590	88.9	0.51	28.4	0.068	3.79
Spent Pulping Liquor (Env.Canada)	0.001428	102.0	0.05	3.571	0.02	1.429
Spent Pulping Liquor (U.S. EPA)	0.001394	99.60	0.44	31.65	0.073	5.275
Agricultural byproducts	NA	112	NA	NA	NA	NA
Solid byproducts	NA	100	NA	NA	NA	NA
Biogas (capture methane)	NA	49.4	NA	NA	NA	NA
Ethanol (100%)	NA	64.9	NA	NA	NA	NA
Biodiesel (100%)	NA	70	NA	NA	NA	NA
Rendered Animal Fat	NA	67.4	NA	NA	NA	NA
Vegetable Oil	NA	77.3	NA	NA	NA	NA
Other Solid Fuels						

Coal Coke	0.00248	86.02	0.03	1.041	0.02	0.694
Tires	N/A	85	N/A	N/A	N/A	N/A
Gaseous Fuels	**CO_2 Emission Factor (kg /m^3)**	**CO_2 Emission Factor (kg /GJ)**	**CH_4 Emission Factor (g/m3)**	**CH_4 Emission Factor (g/GJ)**	**N_2O Emission Factor (g/m3)**	**N_2O Emission Factor (g/GJ)**
Coke Oven Gas	1.6	83.60	0.037	1.933	0.035	1.829
Still Gas – Refineries	1.75	48.50	N/A	N/A	0.0222	0.615
Still Gas – Upgraders	2.14	49.49	N/A	N/A	0.0222	0.513

Source: Environment Canada National Inventory Report on Greenhouse Gases and Sinks, 1990-2007, unless otherwise stated

[1] Assumes 50% moisture content of wood waste

[2] Assumes 12% moisture content of wood waste

Table 20-3: Default Carbon Dioxide Emission Factors for Natural Gas by Province

	Marketable Gas (kg/m^3)	**Marketable Gas (kg/GJ)**	**Non-Marketable Gas (kg/m^3)**	**Non-Marketable Gas (kg/GJ)**
Quebec	1.878	49.01	Not occurring	Not occurring
Ontario	1.879	49.03	Not occurring	Not occurring
Manitoba	1.877	48.98	Not occurring	Not occurring
British Columbia	1.916	50.00	2.151	56.13

Source: Environment Canada National Inventory Report on Greenhouse Gases and Sinks, 1990-2007

Table 20-4: Default Methane and Nitrous Oxide Emission Factors for Natural Gas

	CH_4 (g/m^3)	**CH_4 (g/GJ)**	**N_2O (g/m^3)**	**N_2O (g/GJ)**
Electric Utilities	0.49	12.79	0.049	1.279
Industrial	0.037	0.966	0.033	0.861
Producer Consumption (Non-marketable)	6.5	169.6	0.06	1.566
Pipelines	1.9	49.58	0.05	1.305
Cement	0.037	0.966	0.034	0.887
Manufacturing Industries	0.037	0.966	0.033	0.861
Residential, Construction, Commercial/Institutional, Agriculture	0.037	0.966	0.035	0.913

Source: Environment Canada National Inventory Report on Greenhouse Gases and Sinks, 1990-2007

Table 20-5: Default Carbon Dioxide Emission Factors for Coal

	Emission Factor (kg CO_2/tonne coal)	**Emission Factor (kg CO_2/GJ)**
Quebec		
- Canadian Bituminous	0.00225	85.5
- U.S. Bituminous	0.00234	88.9
- Anthracite	0.00239	86.3
Ontario		
- Canadian Bituminous	0.00225	85.5

- U.S. Bituminous	0.00243	81.5
- Sub-bituminous	0.00173	90.3
- Lignite	0.00148	98.7
- Anthracite	0.00239	86.3
Manitoba		
- Canadian Bituminous	0.00225	85.5
- U.S. Bituminous	0.00243	81.5
- Sub-bituminous	0.00173	90.3
- Lignite	0.00142	94.7
- Anthracite	0.00239	86.3
British Columbia		
- Canadian Bituminous	0.00207	78.6
- U.S. Bituminous	0.00243	81.5
- Sub-bituminous	0.00177	92.4

Source: Environment Canada National Inventory Report on Greenhouse Gases and Sinks, 1990-2007

Table 20-6: Default Methane and Nitrous Oxide Emission Factors for Coal

	CH_4 Emission Factor (g/kg)	N_2O Emission Factor (g/kg)
Electric Utilities	0.022	0.032
Industry and Heat and Steam Plants	0.03	0.02
Residential, Public Administration	4	0.02

Source: Environment Canada National Inventory Report on Greenhouse Gases and Sinks, 1990-2007

Table 20-7: Other Emission Factors

	CO_2 Emission Factor (kg/GJ)	CH_4 Emission Factor (g/GJ)	N_2O Emission Factor (g/GJ)
Municipal Solid Waste	85.6	30	4
Peat	103	1	1.5

Source: 2006 IPCC Guidelines for National Greenhouse Gas Inventories, except the CO_2 emission factor for municipal solid waste is from the U.S. EPA from table C-1 of 40 CFR 98 subpart C.

ON.140   Glass Production

ON.141   Source Category Definition

A glass manufacturing facility manufactures flat glass, container glass, pressed and blown glass, or wool fiberglass by melting a mixture of raw materials to produce molten glass and form the molten glass into sheets, containers, fibers, or other shapes. A glass manufacturing facility uses one or more glass melting furnaces to produce glass. A glass melting furnace that is an experimental furnace or a research and development process unit is not subject to this method.

ON.142   Greenhouse Gas Reporting Requirements

For the purpose of Section 6 of the Regulation the annual emissions data report for glass production shall include the following information at the facility level calculated in accordance with this method:

(a) Total CO_2 process emissions from all glass melting furnaces (tonnes).

(b) Total CO_2, CH_4 and N_2O combustion emissions from all glass melting furnaces (tonnes). The person must calculate and report these emissions under ON.20 by following the requirements of ON.20.

(c) Total CO_2, CH_4, and N_2O emissions from all stationary fuel combustion units other than glass melting furnaces (tonnes). The person must report these emissions under ON.23 by following the requirements of ON.20.

(d) If a CEMS is used to measure CO_2 emissions, report under this method the relevant information required under ON.23(d) for Calculation Methodology 4 and the following information:

 (1) Annual quantity of glass produced (tonnes).

(e) If a CEMS is not used to determine CO_2 emissions from glass melting furnaces, and process CO_2 emissions are calculated according to the procedures specified in ON.143(b), report the following information:

 (1) Annual quantity of each carbonate-based raw material charged (tonnes) for all furnaces combined.

 (2) Annual quantity of glass produced (tonnes) from all furnaces combined.

 (3) Total number of glass melting furnaces.

(f) The number of times in the reporting year that missing data procedures were followed to measure monthly quantities of carbonate-based raw materials or mass fraction of the carbonate-based minerals for each glass melting furnace

ON.143   Calculation of CO_2 Emissions

The person must calculate the annual process CO_2 emissions from each glass melting furnace using the procedure in paragraphs (a) and (b) of this section.

(a) For each glass melting furnace that meets the conditions specified in ON.23(e)(4), the person must calculate under this source the combined process and combustion CO_2 emissions by operating and maintaining a CEMS to measure CO_2 emissions according to Calculation Methodology 4 specified in ON.23(d) and all associated requirements in ON.20.

(b) For each glass melting furnace that is not subject to the requirements in paragraph (a) of this section, use either the procedure in paragraph (b)(1) of this section or the procedure in paragraphs (b)(2) through (b)(7) of this section, except as specified in paragraph (c) of this section.

   (1) Calculate the combined process and combustion CO_2 emissions by operating and maintaining a CEMS to measure CO_2 emissions according to Calculation Methodology 4 specified in ON.23(d).

   (2) Calculate the process and combustion CO_2 emissions separately using the procedures specified in paragraphs (b)(2)(i) through (b)(2)(iv) of this section.

        (i) For each carbonate-based raw material charged to the furnace, obtain from the supplier of the raw material the carbonate-based mineral mass fraction.

        (ii) Determine the quantity of each carbonate-based raw material charged to the furnace.

        (iii) Apply the appropriate emission factor for each carbonate-based raw material charged to the furnace, as shown in Table 140-1 to this method.

        (iv) Use Equation 140-1 of this section to calculate process mass emissions of CO_2 for each furnace:

$$E_{CO2} = \sum_{i=1}^{n} (M_i \times MF_i \times EF_i \times F_i)$$ **Equation 140-1**

Where:
$\quad$ E_{CO2} $\quad$ = $\quad$ Process emissions of CO_2 from the furnace (tonnes).
$\quad$ n $\quad$ = $\quad$ Number of carbonate-based raw materials charged to furnace.
$\quad$ MF_i $\quad$ = $\quad$ Annual average mass fraction of carbonate-based mineral i in carbonate-based raw material i (weight fraction).
$\quad$ M_i $\quad$ = $\quad$ Annual amount of carbonate-based raw material i charged to furnace (tonnes).
$\quad$ EF_i $\quad$ = $\quad$ Emission factor for carbonate-based mineral i (tonnes CO_2 per tonne carbonate-based mineral as shown in Table 140-1.
$\quad$ F_i $\quad$ = $\quad$ Fraction of calcination achieved for carbonate-based mineral i, 1.0 for completed calcination(weight fraction).

(v) The person must calculate and report the total process CO_2 emissions from glass melting furnaces at the facility using Equation 140-2 of this section:

$$CO_2 = \sum_{i=1}^{k} E_{CO_2 i}$$ **Equation 140-2**

Where:

CO₂   =   Annual process CO_2 emissions from glass manufacturing facility (tonnes).

E_{CO2i} =   Annual CO_2 emissions from glass melting furnace i (tonnes).

k   =   Number of glass melting furnaces.

(vi) Calculate and report under ON.20 the combustion CO_2 emissions in the glass furnace according to the applicable requirements in ON.20.

ON.144   Sampling, Analysis, and Measurement Requirements

(a) The person must measure annual amounts of carbonate-based raw materials charged to each glass melting furnace from monthly measurements using plant instruments used for accounting purposes, such as calibrated scales or weigh hoppers. Total annual mass charged to glass melting furnaces at the facility shall be compared to records of raw material purchases for the year.

(b) The person must measure carbonate-based mineral mass fractions at least annually to verify the mass fraction data provided by the supplier of the raw material; such measurements shall be based on sampling and chemical analysis conducted by a certified laboratory using ASTM D3682 - Standard Test Method for Major and Minor Elements in Combustion Residues from Coal Utilization Processes.

(c) The person must determine the annual average mass fraction for the carbonate-based mineral in each carbonate-based raw material by calculating an arithmetic average of the monthly data obtained from raw material suppliers or sampling and chemical analysis.

(d) As an alternative to data provided by the raw material supplier, a value of 1.0 can be used for the monthly mass fraction (MF_i) of carbonate-based mineral i in Equation 140-1 of this section.

(e) The person must determine on an annual basis the calcination fraction for each carbonate consumed based on sampling and chemical analysis using an industry consensus standard. This chemical analysis must be conducted using an x-ray fluorescence test or other enhanced testing method published by an industry consensus standards organization (e.g., ASTM, ASME, API, etc.).

ON.145   Procedures for Estimating Missing Data.

The person is required to retain a complete record of all measured parameters used in the GHG emissions calculations (e.g., carbonate raw materials consumed, etc.). If the

monitoring and quality assurance procedures in ON.144 cannot be followed and data is missing, the person must use the most appropriate of the missing data procedures in paragraphs (a) and (b) of this section. The person must document and keep records of the procedures used for all such missing value estimates as required by the Regulation.

(a) For missing data on the monthly amounts of carbonate-based raw materials charged to any glass melting furnace use the best available estimate(s) of the parameter(s), based on all available process data or data used for accounting purposes, such as purchase records.

(b) For missing data on the mass fractions of carbonate-based minerals in the carbonate-based raw materials assume that the mass fraction of each carbonate based mineral is 1.0.

Table 140-1 - CO$_2$ Emission Factors for Carbonate-Based Minerals

Carbonate-Based Raw Material – Mineral	CO$_2$ Emission Factor[a]
Limestone – CaCO$_3$	0.43971
Dolomite – CaMg(CO$_3$)$_2$	0.47732
Sodium carbonate/soda ash – Na$_2$CO$_3$	0.41492

[a] Emission factors in units of tonnes of CO$_2$ emitted per tonne of carbonate-based mineral charged to the furnace.

ON.120   HFC-22 Production and HFC-23 Destruction

ON.121   Source Definition

The HCFC-22 production and HFC-23 destruction source consists of HCFC-22 production processes and HFC-23 destruction processes.

- An HCFC-22 production process produces HCFC-22 (chlorodifluoromethane, or CHClF2) from chloroform (CHCl3) and hydrogen fluoride (HF).

- An HFC-23 destruction process is any process in which HFC-23 undergoes destruction. An HFC-23 destruction process may or may not be co-located with an HCFC-22 production process at the same facility.

ON.122   Greenhouse Gas Reporting Requirements

For the purpose of Section 6 of the Regulation the annual emissions data report for HFC-22 production and HFC-23 destruction shall include the following information at the facility level calculated in accordance with this method:

(a) HFC-23 emissions from HCFC-22 production processes and HFC-23 destruction processes.

(b) Emissions of CO_2, CH_4, and N_2O from stationary combustion units not covered by this method shall follow the requirements of ON.20 (tonnes).

ON.123   Calculation of GHG Emissions

Quantify emissions in accordance with U.S. EPA 40 CFR 98 Subpart O Section 98.153.

ON.124   Sampling, Analysis, and Measurement Requirements

Sampling, analysis and measurement requirements for this source shall be done in accordance with U.S. EPA 40 CFR 98 Subpart O Section 98.154.

ON.125   Procedures for Estimating Missing Data

Missing data requirements for this source shall be estimated in accordance with U.S. EPA 40 CFR 98 Subpart O Section 98.155.

ON.130   Hydrogen Production

ON.131   Source Definition

A hydrogen production process produces hydrogen gas by steam hydrocarbon reforming, partial oxidation of hydrocarbons, or other transformation of hydrocarbon feedstock. The hydrogen produced may be either transferred offsite or used onsite at petrochemical, ammonia production, refineries, and other plants.

ON.132   Greenhouse Gas Reporting Requirements

For the purpose of Section 6 of the Regulation the annual emissions data report for hydrogen production shall include the following information at the facility level calculated in accordance with this method:

(a) Process CO_2 Emissions. The CO_2 process emissions from the hydrogen production process (tonnes).

(b) Feedstock Consumption (if estimating emissions using mass balance approach in ON.133(b)). Annual feedstock consumption by feedstock type (including petroleum coke) reported in units of million standard cubic metres for gases, kilolitres for liquids, tonnes for non-biomass solids, and bone dry tonnes for biomass-derived solid fuels.

(c) Production. Annual hydrogen produced (tonnes).

(d) Stationary Combustion Units. Report CO_2, N_2O, and CH_4 emissions as specified in ON.20 (tonnes).

ON.133   Calculation of Greenhouse Gas Emissions

The person shall calculate and report CO_2 process emissions using the methods in paragraphs (a) or (b) of this section.

(a) Continuous Emission Monitoring Systems. The person may calculate CO_2 process emissions using CEMS. The person must comply with the requirements in section ON.20.

(b) Feedstock Material Balance. The person may calculate CO_2 process emissions using the following method.

   (1) <u>Gaseous fuel and feedstock.</u> The person must calculate the annual CO_2 process emissions from gaseous fuel and feedstock according to Equation 130-1 of this section:

$$CO_2 = (\sum_{n=1}^{k} 3.664 * Fdstk_n * CC_n * \frac{MW}{MVC}) * 0.001 \qquad \textbf{Equation 130-1}$$

Where:
$\quad CO_2 \qquad$ = $\quad$ Annual CO_2 process emissions arising from fuel and feedstock consumption (tonnes/yr).

$Fdstk_n$ =   Volume of the gaseous fuel and feedstock used in month n (m^3 at standard conditions of 20°C and 1 atmosphere of fuel and feedstock).

CC_n =   Weighted average carbon content of the gaseous fuel and feedstock, from the results of one or more analyses for month n (Rm^3 at reference temperature and pressure conditions as used by the facility). If a mass flow meter is used, measure the feedstock used in month n in kg and replace the term "MW/MVC" with "1".

MW   =   Molecular weight of the gaseous fuel and feedstock (kg/kg-mole).

MVC   =   Molar volume conversion factor at the same reference conditions as the above $Fdstk_n$ (Rm3/kg-mole). MVC can be

          =   8.3145 * [273.16 + reference temperature in °C] / [reference pressure in kilopascal].

k   =   Months in the year.

3.664   =   Ratio of molecular weights, CO_2 to carbon.

0.001   =   Conversion factor from kg to tonnes.

(2) <u>Liquid fuel and feedstock</u>. The person must calculate the annual CO_2 process emissions from liquid fuel and feedstock according to Equation 130-2 of this section:

$$CO_2 = (\sum_{n=1}^{k} 3.664 * Fdstk_n * CC_n) * 0.001 \qquad \textbf{Equation 130-2}$$

Where:

CO_2 =   Annual CO_2 emissions arising from fuel and feedstock consumption (tonnes/yr).

$Fdstk_n$ =   Volume of the liquid fuel and feedstock used in month n (m^3 of fuel and feedstock). If a mass flow meter is used, measure the fuel and feedstock used in month n in kg and measure the carbon content of feedstock in kg C per kg of feedstock.

CC_n =   Weighted average carbon content of the liquid fuel and feedstock, from the results of daily analyses for month n (kg of C per m^3 of fuel and feedstock when the usage is measured in m^3, or kg of C per kg of feedstock and fuel when the usage is measured in kg).

k   =   Months in the year.

3.664   =   Ratio of molecular weights, CO_2 to carbon.

0.001   =   Conversion factor from kg to tonnes.

(3) <u>Solid fuel and feedstock.</u> The person must calculate the annual CO_2 process emissions from solid fuel and feedstock according to Equation 130-3 of this section:

$$CO_2 = \sum_{n=1}^{k} 3.664 * (Fdstk_n * CC_n) * 0.001 \qquad \textbf{Equation 130-3}$$

Where:

CO_2 =   Annual CO_2 emissions from fuel and feedstock consumption in tonnes per year month (tonnes/yr).

$Fdstk_n$ =   Mass of solid fuel and feedstock used in month n (kg of fuel and feedstock).

CC_n =   Weighted average carbon content of the solid fuel and feedstock, from the results of daily analyses for month n (kg carbon per kg of fuel and feedstock).

k   =   Months in the year.

3.664   =   Ratio of molecular weights, CO_2 to carbon.

0.001   =   Conversion factor from kg to tonnes.

(c) If GHG emissions from a hydrogen production process unit are vented through the same stack as any combustion unit or process equipment that reports CO_2 emissions using a CEMS that complies with ON.20, then the calculation methodology in paragraph (b) of this section shall not be used to calculate process emissions. The person shall report the combined stack emissions according to the CEMS methodology in ON.20.

ON.134   Sampling, Analysis, and Measurement Requirements

(a) Persons using CEMS to estimate CO_2 emissions shall comply with the monitoring requirements in section ON.20.

(b) Persons using the methods in section ON.133 (b) or paragraph (c) of this section shall perform the following monitoring:

(1) The person shall measure the feedstock consumption rate daily.

(2) The person shall collect samples of each feedstock consumed and analyze each sample for carbon content using the methods specified in paragraph (c) of this section. For natural gas feedstock not mixed with another feedstock prior to consumption, samples shall be collected and analyzed once per month. For all other feedstocks, samples shall be collected and analyzed daily and a weighted average established for month n. Daily samples may be combined to generate a monthly composite sample for carbon analysis. The samples shall be collected from a location in the feedstock handling system that provides samples representative of the feedstock consumed in the hydrogen production process.

(3) Persons shall quantify the hydrogen produced daily.

(4) Persons shall quantify the CO_2 and CO collected and transferred off-site quarterly.

(c) The person must use the following methods, as applicable, to determine the carbon content of the feedstocks:

(1) ASTM D2013 - Standard Practice of Preparing Coal Samples for Analysis.

(2) ASTM D2234/D2234M - Standard Practice for Collection of a Gross Sample of Coal.

(3) ASTM D2597 - Standard Test Method for Analysis of Demethanized Hydrocarbon Liquid Mixtures Containing Nitrogen and Carbon Dioxide by Gas Chromatography.

(4) ASTM D3176 - Standard Practice for Ultimate Analysis of Coal and Coke.

(5) ASTM D4057 - Standard Practice for Manual Sampling of Petroleum and Petroleum Products.

(6) ASTM D4177 - Standard Practice for Automatic Sampling of Petroleum and Petroleum Products.

(7) ASTM D6609 - Standard Guide for Part-Stream Sampling of Coal.

(8) ASTM D6883 - Standard Practice for Manual Sampling of Stationary Coal from Railroad Cars, Barges, Trucks, or Stockpiles.

(9) ASTM D7430 - Standard Practice for Mechanical Sampling of Coal.

(10)   ASTM UOP539 - Refinery Gas Analysis by Gas Chromatography.

(11)   GPA 2261–00 Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography.

(12)   ISO 3170: Petroleum Liquids— Manual sampling—Third Edition.

(13)   ISO 3171: Petroleum Liquids— Automatic pipeline sampling—Second Edition.

ON.135   Procedures for Estimating Missing Data

The person is required to retain a complete record of all measured parameters used in the GHG emissions calculations. Therefore, whenever a quality-assured value of a required parameter is unavailable (e.g., if a meter malfunctions during unit operation), a substitute data value for the missing parameter must be used in the calculations as specified in paragraphs (a), (b), and (c) of this section:

(a)   For each missing value of the monthly fuel and feedstock consumption, the substitute data value must be the best available estimate of the fuel and feedstock consumption, based on all available process data (e.g., hydrogen production, electrical load, and operating hours). The person must document and keep records of the procedures used for all such estimates as required by the Regulation.

(b)   For each missing value of the carbon content or molecular weight of the fuel and feedstock, the substitute data value must be the arithmetic average of the quality-assured values of carbon contents or molecular weight of the fuel and feedstock immediately preceding and immediately following the missing data incident. If no quality-assured data on carbon contents or molecular weight of the fuel and feedstock are available prior to the missing data incident, the substitute data value must be the first quality-assured value for carbon contents or molecular weight of the fuel and feedstock obtained after the missing data period. The person must document and keep records of the procedures used for all such estimates as required by the Regulation.

(c)   For missing CEMS data, the person must use the missing data procedures in ON.20.

ON.150   Iron and Steel Manufacturing

ON. 151   Source Definition

Iron and steel manufacturing comprises five categories: taconite iron ore processing, primary facilities that produce both iron and steel, secondary steelmaking facilities, iron production facilities, and offsite production of metallurgical coke. These processes may occur together in an "integrated" facility or they may occur in separate offsite facilities.

ON.152   Greenhouse Gas Reporting Requirements

For the purpose of Section 6 of the Regulation the annual emissions data report for iron and steel manufacturing shall include the following information at the facility level calculated in accordance with this method:

(a) Annual process CO_2 emissions (tonnes) for the following processes:

    (1) Taconite indurating furnace

    (2) Basic oxygen furnace (BOF)

    (3) Coke making operation

    (4) Sinter process

    (5) Electric arc furnace (EAF)

    (6) Argon-oxygen decarburization vessel

    (7) Direct reduction furnace

    (8) Blast furnace

(b) Annual production/usage quantities (tonnes) for the following processes:

    (1) Taconite indurating furnace – fired pellets produced on-site

    (2) BOF – steel produced on-site

    (3) Coke making operation – coke produced and coal charged

    (4) Sinter process – sinter produced

    (5) EAF – steel produced on-site

    (6) Argon-oxygen decarburization vessel – molten steel charged

    (7) Direct reduction furnace – iron produced

    (8) Blast furnace – iron produced

(c) CO_2, N_2O, and CH_4 emissions, not accounted for elsewhere in ON.150, from stationary combustion units as specified in ON.20 (tonnes). Report these emissions from stationary combustion for each of the following devices:

    (1) Taconite indurating furnace

    (2) BOF

(3) Coke oven batteries

(4) Sintering furnace

(5) EAF

(6) Argon-oxygen decarburization vessel

(7) Direct reduction furnace

(8) Blast furnace

(9) Any other stoves, boiler, process heaters, reheat furnaces and other combustion sources.

ON.153   Calculation of CO_2 Emissions

(a) Process CO_2 emissions. Determine process CO_2 emissions as specified under either paragraph (1) or (2) of this section.

   (1) Continuous emissions monitoring systems (CEMS) as specified in ON.23(d).

   (2) Calculation methodologies specified in paragraph (b) of this section.

(b) Process CO_2 Emissions Calculation Methodology. Calculate CO_2 process emissions for each taconite indurating furnace, basic oxygen furnace, non-recovery coke oven battery, sinter process, EAF, argon-oxygen decarburization vessel, blast furnace, and direct reduction furnace using the following mass balance approaches specified in paragraphs (b)(1) through (b)(8). Specific process inputs or outputs that contribute less than 1 per cent of the total mass of carbon into or out of the process do not have to be included in the paragraphs (b)(1) through (b)(8) mass balances.

   (1) Calculate taconite indurating furnace CO_2 emissions using Equation 150-1:

$$E_T = \left[(T \times C_T) - (P \times C_P) - (R \times C_R) \right] \times 3.664$$

<div align="right">**Equation 150-1**</div>

Where:

E_T =   Annual CO_2 emissions from taconite indurating furnace (tonnes);
T =   Annual mass of greenball (taconite) pellets fed to furnace (tonnes);
C_T =   Carbon content of greenball (taconite) pellets (tonnes C/tonnes taconite pellets);
P =   Annual mass of fired pellets produced by the furnace (tonnes);
C_P =   Carbon content of fired pellets (tonnes C/tonnes fired pellets);
R =   Annual mass of air pollution control residue collected (tonnes);
C_R =   Carbon content of air pollution control residue (tonnes C/tonnes residue);
3.664   =   Conversion factor from tonnes of C to tonnes of CO_2.

   (2) Calculate basic oxygen process furnace CO_2 emissions using Equation 150-2:

$$E_{BOF} = [(I \times C_I) + (SC \times C_{SC}) + (FL \times C_{FL}) + (CAR \times C_{CAR}) - (ST \times C_{ST}) - (SL \times C_{SL}) - (BOG \times C_{BOG}) - (R \times C_R)] \times 3.664$$

Equation 150-2

Where:

E_{BOF}	=	Annual CO_2 emissions from basic oxygen furnaces (tonnes);
I	=	Annual mass of molten iron charged to furnace (tonnes);
C_I	=	Carbon content of molten iron (tonnes C/tonnes molten iron);
SC	=	Annual mass of ferrous scrap charged to furnace (tonnes);
C_{SC}	=	Carbon content of ferrous scrap (tonnes C/tonnes ferrous scrap);
FL	=	Annual mass for flux materials (e.g., limestone, dolomite, etc.) charged to furnace (tonnes);
C_{FL}	=	Carbon content of flux materials (tonnes C/tonnes flux material);
CAR	=	Annual mass of carbonaceous material (e.g., coal, coke, etc.) charged to furnace (tonnes);
C_{CAR}	=	Carbon content of carbonaceous material (tonnes C/tonnes carbonaceous material);
ST	=	Annual mass of molten raw steel produced by furnace (tonnes);
C_{ST}	=	Carbon content of steel (tonnes C/tonnes steel);
SL	=	Annual mass of slag produced by furnace (tonnes);
C_{SL}	=	Carbon content of slag (tonnes C/tonnes slag);
BOG	=	Annual mass of basic oxygen furnace gas transferred off site (tonnes);
C_{BOG}	=	Carbon content of basic oxygen furnace gas transferred off site (tonnes C/tonnes basic oxygen furnace gas);
R	=	Annual mass of air pollution control residue collected (tonnes);
C_R	=	Carbon content of air pollution control residue (tonnes C/tonnes residue);

(3) Calculate coke oven battery CO_2 emissions using Equation 150-3:

$$E_{coke} = [(CC \times C_{CC}) - (CO \times C_{CO}) - (BY \times C_{BY}) - (R \times C_R) - (COG \times C_{COG})] \times 3.664$$

Equation 150-3

Where:

E_{coke}	=	Annual CO_2 emissions from coke production (tonnes);
CC	=	Annual mass of coking coal charged to battery (tonnes);
C_{CC}	=	Carbon content of coking coal (tonnes C/tonnes coking coal);
CO	=	Annual mass of coke produced (tonnes);
C_{CC}	=	Carbon content of coke (tonnes C/tonnes coke);
BY	=	Annual mass of by-product from by-product coke oven battery (tonnes);
C_{BY}	=	Carbon content of by-product (tonnes C/tonnes by-product);

R   =   Quantity of air pollution control residue collected (tonnes);
C_R =   Carbon content of air pollution control residue (tonnes C/tonnes residue);
COG   =   Annual mass of coke oven gas transferred off site (tonnes);
C_{COG} =   Carbon content of coke oven gas transferred off site (tonnes C/tonnes coke oven gas);
3.664 =   Conversion factor from tonnes of C to tonnes of CO_2.

(4) Calculate sinter process CO_2 emissions using Equation 150-4:

$$E_{sinter} = \left[(CAR \times C_{CAR}) + (FE \times C_{FE}) - (S \times C_S) - (R \times C_R) \right] \times 3.664$$

Equation 150-4

Where:
E_{sinter} =   Annual CO_2 emissions from sinter process (tonnes);
CAR   =   Annual mass of carbonaceous material (e.g., coal, coke, etc.) charged to furnace (tonnes);
C_{CAR} =   Carbon content of carbonaceous material (tonnes C/tonnes carbonaceous material);
FE   =   Annual mass of sinter feed material (tonnes);
C_{FE} =   Carbon content of sinter feed material (tonnes C/tonnes sinter feed material);
S   =   Annual mass of sinter produced (tonnes);
C_S =   Carbon content of sinter produced (tonnes C/tonnes sinter);
R   =   Quantity of air pollution control residue collected (tonnes);
C_R =   Carbon content of air pollution control residue (tonnes C/tonnes residue);
3.664 =   Conversion factor from tonnes of C to tonnes of CO_2.

(5) Calculate electric arc furnace (EAF) CO_2 emissions using Equation 150-5:

$$E_{EAF} = \left[(I \times C_I) + (SC \times C_{SC}) + (FL \times C_{FL}) + (EL \times C_{EL}) + (CAR \times C_{CAR}) - (ST \times C_{ST}) - (SL \times C_{SL}) - (R \times C_R) \right] \times 3.664$$

Equation 150-5

Where:
E_{EAF} =   Annual CO_2 emissions from EAF (tonnes);
I   =   Annual mass of direct reduced iron (if any) charged to furnace (tonnes);
C_I =   Carbon content of direct reduced iron (tonnes C/tonnes direct reduced iron);
SC   =   Annual mass of ferrous scrap charged to furnace (tonnes);
C_{SC} =   Carbon content of ferrous scrap (tonnes C/tonnes ferrous scrap);
FL   =   Annual mass for flux materials (e.g., limestone, dolomite, etc.) charged to furnace (tonnes);

C_{FL} =   Carbon content of flux materials (tonnes C/tonnes flux material);

EL   =   Annual mass for carbon electrodes consumed (tonnes);

C_{EL} =   Carbon content of carbon electrodes (tonnes C/tonnes carbon electrode);

CAR   =   Annual mass of carbonaceous material (e.g., coal, coke, etc.) charged to furnace (tonnes);

C_{CAR} =   Carbon content of carbonaceous material (tonnes C/tonnes carbonaceous material);

ST   =   Annual mass of molten raw steel produced by furnace (tonnes);

C_{ST} =   Carbon content of steel (tonnes C/tonnes steel);

SL   =   Annual mass of slag produced by furnace (tonnes);

C_{SL} =   Carbon content of slag (tonnes C/tonnes slag);

R   =   Annual mass of air pollution control residue collected (tonnes);

C_R =   Carbon content of air pollution control residue (tonnes C/tonnes residue);

3.664   =   Conversion factor from tonnes of C to tonnes of CO_2.

(6) Calculate argon-oxygen decarburization vessel CO_2 emissions using Equation 150-6:

$$E_{AOD} = \left[Steel \times \left(C_{in} - C_{out} \right) - \left(R \times C_R \right) \right] \times 3.664$$

Equation 150-6

Where:

E_{AOD} =   Annual CO_2 emissions from argon-oxygen decarburization vessels (tonnes);

Steel   =   Annual mass of molten steel charged to vessel (tonnes);

C_{in} =   Carbon content of molten steel before decarburization (tonnes C/tonnes molten steel);

C_{out} =   Carbon content of molten steel after decarburization (tonnes C/tonnes molten steel);

R   =   Annual mass of air pollution control residue collected (tonnes);

C_R =   Carbon content of air pollution control residue (tonnes C/tonnes residue);

3.664   =   Conversion factor from tonnes of C to tonnes of CO_2.

(7) Calculate direct reduction furnace CO_2 emissions using Equation 150-7:

$$E_{DR} = \left[\left(Ore \times C_{Ore} \right) + \sum \left(CAR \times C_{CAR} \right) + \sum \left(OT \times C_{OT} \right) - \left(I \times C_I \right) - \left(NM \times C_{NM} \right) - \left(R \times C_R \right) \right] \times 3.664$$

Equation 150-7

Where:

E_{DR} =   Annual CO_2 emissions from direct reduction furnace (tonnes);

Ore   =   Annual mass of iron ore or iron ore pellets fed to the furnace (tonnes);

C_{Ore} =   Carbon content of iron ore or iron ore pellets (tonnes C/tonnes iron ore or iron ore pellets);

CAR   =   Annual mass of non-fuel carbonaceous materials (e.g., coal, coke, by-products, etc.) charged to furnace (tonnes);

C_{CAR} =   Carbon content of non-fuel carbonaceous materials (tonnes C/tonnes non-fuel carbonaceous material);

OT   =   Annual mass of other materials charged to furnace (tonnes);

C_{OT} =   Carbon content of other materials (tonnes C/tonnes other materials);

I   =   Annual mass of iron produced (tonnes);

C_I =   Carbon content of iron (tonnes C/tonnes iron);

NM   =   Annual mass for non-metallic materials produced (tonnes);

C_{NM} =   Carbon content of non-metallic materials (tonnes C/tonnes non-metallic minerals);

R   =   Annual mass of air pollution control residue collected (tonnes);

C_R =   Carbon content of air pollution control residue (tonnes C/tonnes residue);

3.664   =   Conversion factor from tonnes of C to tonnes of CO_2.

(8) Calculate blast furnace CO_2 emissions using Equation 150-8:

$$E_{BF} = \left[(Ore \times C_{Ore}) + \sum (CAR \times C_{CAR}) + \sum (F \times C_F) + \sum (OT \times C_{OT}) - (I \times C_I) - (NM \times C_{NM}) - (BG \times C_{BG}) - (R \times C_R) \right] \times 3.664$$

Equation 150-8

Where:

E_{BF} =   Annual CO_2 emissions from blast furnace (tonnes);

Ore   =   Annual mass of iron ore or iron ore pellets fed to the furnace (tonnes);

C_{Ore} =   Carbon content of iron ore or iron ore pellets (tonnes C/tonnes iron ore or iron ore pellets);

CAR   =   Annual mass of non-fuel carbonaceous materials (e.g., coal, coke, by-products, etc.) charged to furnace (tonnes);

C_{CAR} =   Carbon content of non-fuel carbonaceous materials (tonnes C/tonnes non-fuel carbonaceous material);

F   =   Annual mass for flux materials (e.g., limestone, dolomite, etc.) charged to furnace (tonnes);

C_F =   Carbon content of flux materials (tonnes C/tonnes flux material);

OT   =   Annual mass of other materials charged to furnace (tonnes);

C_{OT} =   Carbon content of other materials (tonnes C/tonnes other materials);

I   =   Annual mass of iron produced (tonnes);

C_I =   Carbon content of iron (tonnes C/tonnes iron);

NM   =   Annual mass for non-metallic materials produced (tonnes);

C_{NM} = Carbon content of non-metallic materials (tonnes C/tonnes non-metallic minerals);

BG = Annual mass for blast furnace gas transferred off-site (tonnes);

C_{BG} = Carbon content of blast furnace gas (tonnes C/tonnes blast furnace gas);

R = Annual mass of air pollution control residue collected (tonnes);

C_R = Carbon content of air pollution control residue (tonnes C/tonnes residue);

3.664 = Conversion factor from tonnes of C to tonnes of CO_2.

(9) Calculate total CO_2 emissions using Equation 150-9:

$$E_{CO2} = E_T + E_{BOF} + E_{coke} + E_{sinter} + E_{EAF} + E_{AOD} + E_{DR} + E_{BF} \qquad \textbf{Equation 150-9}$$

Where:

E_{CO2} = Total CO_2 emissions (tonnes);

E_T = Emissions from taconite indurating furnace (tonnes);

E_{BOF} = Emissions from basic oxygen furnace (BOF) (tonnes);

E_{coke} = Emissions from coke production (tonnes);

E_{sinter} = Emissions from sinter production (tonnes);

E_{EAF} = Emissions from electric arc furnace (EAF) (tonnes);

E_{AOD} = Emissions from argon-oxygen decarburization vessels (tonnes);

E_{DR} = Emissions from direct reduction furnace (tonnes);

E_{BF} = Emissions from blast furnace (tonnes);

ON.154   Calculation of CH_4 Emissions

(a) Process CH_4 emissions. Determine process CH_4 emissions as specified under either paragraph (1) or paragraph (2) of this section.

(1) Continuous emissions monitoring systems (CEMS) as specified in ON.23(d).

(2) Site-specific emission factors.

ON.155   Sampling, Analysis, and Measurement Requirements

The annual mass of each material used in the ON.153 mass balance methodologies shall be determined using plant instruments used for accounting purposes, including either direct measurement of the quantity of material used in the process or by calculations using process operating information.

The average carbon content of each material used shall be determined as specified under paragraph (a) or (b) of this section.

(a) Obtain carbon content by collecting and analyzing at least three representative samples of the material each year using one of the following methods:

(1) For iron ore, taconite pellets, and other iron-bearing materials, use ASTM E1915 - Standard Test Methods for Analysis of Metal Bearing Ores and Related Materials by Combustion Infrared-Absorption Spectrometry.

(2) For iron and ferrous scrap, use ASTM E1019 - Standard Test Methods for Determination of Carbon, Sulphur, Nitrogen, and Oxygen in Steel, Iron, Nickel, and Cobalt Alloys by Various Combustion and Fusion Techniques".

(3) For coal, coke, and other carbonaceous materials (e.g., electrodes, etc.), use ASTM D5373 - Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal or ASTM D5142 - Standard Test Methods for Proximate Analysis of the Analysis Sample of Coal and Coke by Instrumental Procedures, for petroleum liquid based fuels and liquid waste-derived fuels.

(4) For steel, use one of the methods described in subparagraph (i) through (iv):

> (iii) ASM CS-104 UNS No. G10460 "Carbon Steel of Medium Carbon Content".
>
> (iv) ISO/TR 15349-1: 1998 "Unalloyed steel – Determination of low carbon content, Part 1: Infrared absorption method after combustion in an electric resistance furnace (by peak separation) (1998-10-15) – First Edition".
>
> (v) ISO/TR 15349-3: 1998 "Unalloyed steel – Determination of low carbon content, Part 3: Infrared absorption method after combustion in an electric resistance furnace (with preheating) (1998-10-15) – First Edition".
>
> (vi) ASTM E415 - Standard Test Method for Atomic Emission Vacuum Spectrometric Analysis of Carbon and Low-Alloy Steel.

(5) For flux (i.e., limestone or dolomite) and slag, use ASTM C25 - Standard Test Methods for Chemical Analysis of Limestone, Quicklime, and Hydrated Lime.

(6) For fuels, determine carbon content and molecular weight (if applicable) using the applicable methods listed in ON.20.

(7) For steel production by-products (e.g., blast furnace gas, coke oven gas, coal tar, light oil, sinter off gas, slag dust, etc.), use an online instrument that determines carbon content to ±5% or use sampling and analysis listed in ON.25(a) and ON.25(d) respectively.

(b) Obtain carbon content from material vendor or supplier.

ON.156   Procedures for Estimating Missing Data

A complete record of all measured parameters used in the GHG emissions calculations is required. Whenever the monitoring and quality assurance procedures in ON.155 cannot be followed (e.g., if a meter malfunctions during unit operation), a substitute data value for the missing parameter shall be used in the calculations in accordance with paragraphs (a) and (b) of this section. The person must document and keep records of the procedures used for all such estimates.

(a) For missing data on monthly carbon contents of feedstock or the waste recycle stream, the substitute data value shall be the arithmetic average of the quality-assured values

of that carbon content in the month preceding and the month immediately following the missing data incident. If no quality-assured data is available prior to the missing data incident, the substitute data value shall be the first quality-assured value for carbon content obtained in the month after the missing data period.

(b) For missing feedstock supply rates or waste recycle stream used to determine monthly feedstock consumption or monthly waste recycle stream quantity, you must determine the best available estimate(s) of the parameter(s), based on all available process data.

ON.160   LEAD PRODUCTION

ON.161   Source Definition

The lead production source includes two primary production processes used to produce lead from lead concentrates (i.e., the sintering/smelting process and the direct smelting process). In addition, secondary production or recycling of lead (primarily from scrapped lead acid batteries) is included in the source.

ON.162   Greenhouse Gas Reporting Requirements

For the purpose of Section 6 of the Regulation the annual emissions data report for lead production shall include the following information at the facility level calculated in accordance with this method:

(a) Annual emissions of CO_2 at the facility level (tonnes).

(b) Annual quantities of each material used (tonnes).

(c) Carbon content of each material used (tonnes C/tonne reducing agent).

(d) Inferred waste-based carbon-containing material emission factor (if waste-based reducing agent quantification method used)

(e) If the person use the missing data procedures in ON.165(b), the person must report how the monthly mass of carbon-containing materials with missing data was determined and the number of months the missing data procedures were used.

(f) Emissions of CO_2, CH_4, and N_2O from stationary combustion units not covered by this method shall follow the requirements of ON.20 (tonnes).

ON.163   Calculation of CO_2 Emissions

Calculate total CO_2 emissions as specified under paragraph (a) or (b) of this section.

(a) Determine facility CO_2 emissions using continuous emissions monitoring systems (CEMS) as specified in ON.23(d).

(b) Calculate total CO_2 emissions using Equation 160-1. Specific materials that contribute less than 1 per cent of the total carbon into the process do not have to be included in the calculation using Equation 160-1.

$$E_{Pb} = \sum_x (RA_x \times C_x) \times 3.664$$

Equation 160-1

Where:

$$
\begin{aligned}
E_{Pb} &= \text{Annual } CO_2 \text{ emissions from lead production (tonnes);} \\
RA_x &= \text{Annual quantity of material } x \text{ used (tonnes);} \\
C_x &= \text{Carbon content of material } x \text{ (tonnes C/tonnes of } x\text{);} \\
3.664 &= \text{Conversion factor from tonnes of C to tonnes of } CO_2.
\end{aligned}
$$

ON.164   Sampling, Analysis, and Measurement Requirements

The annual mass of each material introduced into the smelting furnace shall be determined using plant instruments used for accounting purposes, including either direct measurement of the quantity of the material placed in the unit or by calculations using process operating information.

The average carbon content of each material introduced into the smelting furnace shall be determined as specified under paragraph (a), (b), or (c) of this section.

(a) Obtain carbon content by collecting and analyzing at least three representative samples of the material each year using one of the following methods:

     (1) For solid carbonaceous reducing agents and carbon electrodes, use ASTM D5373 - Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal.

     (2) For liquid reducing agents, use one of the methods described in subparagraph (i) through (iv):

         (i) ASTM D2502 - Standard Test Method for Estimation of Molecular Weight (Relative Molecular Mass) of Petroleum Oils from Viscosity Measurements.

         (ii) ASTM D2503 - Standard Test Method for Relative Molecular Mass (Relative Molecular Weight) of Hydrocarbons by Thermoelectric Measurement of Vapor Pressure.

         (iii) ASTM D3238 - Standard Test Method for Calculation of Carbon Distribution and Structural Group Analysis of Petroleum Oils by the n-d-M Method.

         (iv) ASTM D5291 - Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants.

     (3) For gaseous reducing agents, use one of the methods described in subparagraph (i) or (ii):

         (i) ASTM D1945 - Standard Test Method for Analysis of Natural Gas by Gas Chromatography.

         (ii) ASTM D1946 - Standard Practice for Analysis of Reformed Gas by Gas Chromatography.

     (4) For waste-based carbon-containing material, determine carbon content by operating the smelting furnace both with and without the waste-reducing agents while keeping the composition of other material introduced constant.

         (i) To ensure representativeness of waste-based carbon-containing material variability, the specific testing plan (e.g. number of test runs, other process variables to keep constant, timing of runs) for these trials must be approved in writing by the Director.

(b) Obtain carbon content from material vendor or supplier.

ON.165   Procedures for Estimating Missing Data

The person is required to retain a complete record of all measured parameters used in the GHG emissions calculations. Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter shall be used in the calculations as specified in the paragraphs (a) and (b) of this section. The person must document and keep records of the procedures used for all such estimates as required by the Regulation.

(a) For each missing data for the carbon content for the smelting furnaces at the facility that estimate annual process CO_2 emissions using the carbon mass balance procedure in ON.163, 100 per cent data availability is required. The person must repeat the test for average carbon contents of inputs according to the procedures in ON.164 if data is missing.

(b) For missing records of the monthly mass of carbon-containing materials, the substitute data value must be based the best available estimate of the mass of the material from all available process data or data used for accounting purposes (such as purchase records).

ON.170   LIME MANUFACTURING

ON.171   Source Definition

Lime manufacturing is comprised of all processes that are used to manufacture a lime product (e.g., calcium oxide, high calcium quicklime, calcium hydroxide, hydrated lime, dolomitic quick lime, dolomitic hydrate, or other products) by calcination of limestone or other highly calcareous materials such as dolomite, aragonite, chalk, coral, marble, and shell.

This source includes all lime manufacturing plants unless the plant is located at a kraft pulp mill, soda pulp mill, sulfite pulp mill, or only processes sludge containing calcium carbonate from water softening processes. The lime manufacturing source consists of marketed and non-marketed lime manufacturing facilities.

Lime kilns at pulp and paper manufacturing facilities must report emissions under ON.210 (Pulp and Paper Manufacturing).

ON.172   Greenhouse Gas Reporting Requirements

For the purpose of Section 6 of the Regulation the annual emissions data report for lime manufacturing shall include the following information at the facility level calculated in accordance with this method:

(a) Total emissions of CO_2, CH_4, and N_2O in tonnes.

(b) CO_2 process emissions from lime production (tonnes) for all kilns combined and the following information:

    (1) For lime production:

        (i) The emission factor (tonne CO_2/tonne) for each lime type for each month.

        (ii) The quantity of each type of lime produced (tonnes) each month.

        (iii) The calcium oxide (CaO) content (weight fraction) of each lime type for each month.

        (iv) The magnesium oxide (MgO) content (weight fraction) of each lime type for each month.

    (2) For the production of calcined byproducts and wastes:

        (i) The emission factor (tonne CO_2/tonne) for each calcined byproduct/waste type for each quarter.

        (ii) The quantity of each type of calcined byproduct/waste type produced each quarter.

        (iii) The calcium oxide (CaO) content (weight fraction) of each calcined byproduct/waste type for each quarter.

        (iv) The magnesium oxide (MgO) content (weight fraction) of each calcined byproduct/waste type for each quarter.

(3) Number of times during the reporting year that missing data procedures were followed to measure lime production.

(c) CO_2, CH_4, and N_2O emissions from fuel combustion in all kilns combined, following the calculation methodologies and reporting requirements specified in ON.173(c) (tonnes).

(d) CO_2, CH_4, and N_2O emissions from all other fuel combustion units combined (kilns excluded), following the calculation methodologies and reporting requirements specified in ON.20 (tonnes).

(e) If a continuous emissions monitor is used to measure CO_2 emissions from kilns, then the requirements of paragraphs (b) of this section do not apply for CO_2.

(f) Operators of lime plants shall also comply with the reporting requirements for any other applicable source listed in Section 2(1) of the Regulation, including but not limited to the following:

(1) Coal fuel storage as specified in ON.100.

(2) Electricity generating as specified in ON.40.

(3) Cogeneration systems as specified in ON.42(f).

ON.173   Calculation of Greenhouse Gas Emissions from Kilns

(a) Determine process CO_2 emissions as specified under either paragraph (a)(1) or (a)(2) of this section.

(1) Continuous emissions monitoring systems (CEMS) as specified in ON.23(d).

(2) Calculate the sum of CO_2 process emissions from kilns and CO_2 fuel combustion emissions from kilns using the calculation methodologies specified in paragraph (b) and (c) of this section.

(b) Process CO_2 Emissions Calculation Methodology. Calculate total CO_2 process emissions as the sum of emissions from lime production, using the method specified in paragraph (b)(1) of this section.

(1) CO_2 Process Emissions. Calculate CO_2 emissions from the production of each type of lime using Equation 170-1 and a plant-specific lime emission factor and a plant-specific calcined byproduct/waste emission factor as specified in this section.

$$E_{CO_2} = \sum_{m}^{12} \sum_{i} \left[QL_{mi} \times EF_{QL_{mi}} \right] + \sum_{q}^{4} \sum_{j} \left[CBW_{qj} \times EF_{CBW_{qj}} \right]$$ **Equation 170-1**

Where:
$\quad E_{CO2}$ $\quad$ = $\quad$ Annual process CO_2 emissions in tonnes/yr.
$\quad QL_{mi}$ $\quad$ = $\quad$ Quantity of lime type i produced in month m, tonnes.

EF_{QLmi} = Emission factor of lime type i produced in month m, computed as specified in paragraph (b)(2) of this section, tonnes CO_2/tonne lime.

CBW_{qj} = Quantity of calcined byproduct and waste type j produced in quarter q, tonnes.

$EF_{CBW,qj}$ = Emission factor of calcined byproduct/waste type j produced in quarter q, computed as specified in paragraph (b)(3) of this section, tonnes CO_2/tonne byproduct and waste.

(2) Monthly Lime Emission Factor. Calculate a plant-specific lime emission factor (EF_{QL}) for each type of lime and month based on the per cent of measured CaO and MgO content in lime and using Equation 170-2.

$$EF_{QL} = (f_{CaO} \times 0.785) + (f_{MgO} \times 1.092)$$

Equation 170-2

Where:

EF_{QL} = Process CO_2 emission factor for lime produced, tonnes CO_2/tonne lime.

f_{CaO} = CaO content of lime, calculated by subtracting CaO content of lime in uncalcined $CaCO_3$ remaining in lime from total CaO content of lime, tonnes CaO/tonne lime

0.785 = Ratio of molecular weights of CO_2 to CaO.

f_{MgO} = MgO content of lime, calculated by subtracting MgO content of lime in uncalcined $MgCO_3$ remaining in lime from total MgO content of lime, tonnes MgO/tonne lime.

1.092 = Ratio of molecular weights of CO_2 to MgO

(3) Quarterly Calcined Byproduct/Waste Emission Factor. The calcined byproduct/waste emission factor shall be calculated using Equation 170-3.

$$EF_{CBW} = (f_{CaO} \times 0.785) + (f_{MgO} \times 1.092)$$

Equation 170-3

Where:

EF_{CBW} = Process CO_2 Emission factor for calcined byproduct and waste, tonnes CO_2/tonne calcined byproduct and waste.

f_{CaO} = CaO content of byproduct and waste, calculated by subtracting CaO content of byproduct and waste in uncalcined $CaCO_3$ remaining in calcined byproduct and waste from total CaO content of byproduct and waste, tonnes CaO/tonne byproduct and waste.

0.785 = Ratio of molecular weights of CO_2 to CaO .

f_{MgO} = MgO content of byproduct and waste, calculated by subtracting MgO content of byproduct and waste in uncalcined $MgCO_3$ remaining in byproduct and waste from total MgO content of byproduct and waste, tonnes MgO/tonne byproduct and waste .

1.092 = Ratio of molecular weights of CO_2 to MgO

(c) Fuel Combustion Emissions in Kilns. Calculate CO_2, CH_4, and N_2O emissions from stationary fuel combustion emissions following the calculation methodologies specified in ON.20. Operators of lime manufacturing plants that primarily combust biomass-derived fuels and combust fossil fuels only during periods of start-up, shut-down, or malfunction may report CO_2 emissions from fossil fuels using the emission factor methodology in ON.23(a). "Pure" means that the biomass-derived fuels account for 97 per cent of the total amount of carbon in the fuels burned.

ON.174 Sampling, Analysis, and Measurement Requirements

(a) The person must determine the chemical composition (CaO and MgO contents) of each type of lime and each type of calcined byproduct/waste according to paragraph (a)(1) and (a)(2) of this section. Samples for analysis of the calcium oxide and magnesium oxide content of each lime type and each calcined byproduct/waste type should be collected during the same month or quarter as the production data. At least one sample must be collected monthly for each lime type produced during the month and quarterly for each calcined byproduct/waste type produced.

(1) ASTM C25 - Standard Test Methods for Chemical Analysis of Limestone, Quicklime, and Hydrated Lime.

(2) The National Lime Association's CO_2 Emissions Calculation Protocol for the Lime Industry English Units Version, February 5, 2008 Revision – National Lime Association.

(b) The quantity of lime produced and sold is to be estimated monthly using direct measurements (such as rail and truck scales) of lime sales for each lime type, and adjusted to take into account the difference in beginning- and end-of-period inventories of each lime type. The inventory period shall be annual at a minimum.

(c) The quantity of calcined byproduct/waste sold is to be estimated monthly using direct measurements (such as rail and truck scales) of calcined byproduct/waste sales for each calcined byproduct/waste type, and adjusted to take into account the difference in beginning- and end-of-period inventories of each calcined byproduct/waste type. The inventory period shall be annual at a minimum. The quantity of calcined byproduct/waste not sold is to be determined no less often than annually for each calcined/byproduct waste type using direct measurements (such as rail and truck scales), or a calcined byproduct/waste generation rate (i.e. calcined byproduct produced as a factor of lime production).

(d) The person must follow the quality assurance/quality control procedures (including documentation) in National Lime Association's CO_2 Emissions Calculation Protocol for the Lime Industry English Units Version, February 5, 2008 Revision – National Lime Association.

ON.175 Procedures for Estimating Missing Data

The person is required to retain a complete record of all measured parameters used in the GHG emissions calculations (e.g., oxide content, quantity of lime products, etc.). Therefore, whenever a quality-assured value of a required parameter is unavailable, a

substitute data value for the missing parameter shall be used in the calculations as specified in paragraphs (a) or (b) of this section. The person must document and keep records of the procedures used for all such estimates as required by the Regulation.

(a) For each missing value of the quantity of lime produced (by lime type), and quantity of byproduct/waste produced and sold, the substitute data value shall be the best available estimate based on all available process data or data used for accounting purposes (such as purchase records).

(b) For missing values related to the CaO and MgO content, the person must conduct a new composition test.

For Nickel Production, the person shall use the method set out in Appendix 7: ON.260 Copper and Nickel Production.

ON.310   Nitric Acid Manufacturing

ON.311   Source Definition

A nitric acid production facility uses one or more trains to produce weak nitric acid (30 to 70 per cent in strength). A nitric acid train produces weak nitric acid through the catalytic oxidation of ammonia.

ON.312   Greenhouse Gas Reporting Requirements

For the purpose of Section 6 of the Regulation the annual emissions data report for nitric acid manufacturing shall include the following information at the facility level calculated in accordance with this method:

(a) Total N_2O process emissions as required by this method (tonnes)

(b) Annual nitric acid production from the nitric acid facility (tonnes, 100 per cent acid basis).

(c) The person must report under ON.20 the emissions of CO_2, CH_4, and N_2O from each stationary combustion unit by following the requirements of ON.20 (tonnes).

ON.313   Calculation of GHG emissions

(a) The person must determine annual N_2O process emissions from each nitric acid train according to paragraphs (a)(1) or (a)(2) of this section.

   (1) Use a site-specific emission factor and production data according to paragraphs (b) through (h) of this section.

   (2) Request Director approval in writing for another method of determining N_2O emissions according to paragraphs.

(b) The person must conduct an annual performance test according to paragraphs (b)(1) through (b)(3) of this section.

   (1) The person must measure N_2O emissions from the absorber tail gas vent for each nitric acid train using the methods specified in ON.314(b) through (d).

   (2) The person must conduct the performance test under normal process operating conditions and without using N_2O abatement technology (if applicable).

   (3) The person must measure the production rate during the performance test and calculate the production rate for the test period in tonnes (100 per cent acid basis) per hour.

(c) The person must determine an N_2O emissions factor to use in Equation 310-3 of this section according to paragraphs (c)(1) or (c)(2) of this section.

   (1) The person may request Director approval in writing for another method of determining N_2O concentration according to the procedures in paragraphs (a)(2) of this section. Alternative methods include the use of N_2O CEMs.

(2) Using the results of the performance test in paragraph (b) of this section, the person must calculate an average site-specific emission factor for each nitric acid train "t" according to Equation 310-1 of this section:

$$EF_{N2Ot} = \frac{\sum_{1}^{n} \dfrac{C_{N2O} * 1.828 \times 10^{-6} * Q}{P}}{n}$$

Equation 310-1

Where:

EF_{N2Ot} = Average site-specific N_2O emissions factor for nitric acid train "t" (kg N_2O generated/tonne nitric acid produced, 100 per cent acid basis).

C_{N2O} = N_2O concentration for each test run during the performance test (ppm N_2O).

1.828×10^{-6} = Conversion factor (kg/dSm^3-ppm N_2O).

Q = Volumetric flow rate of effluent gas for each test run during the performance test (dSm^3/hr).

P = Production rate for each test run during the performance test (tonnes nitric acid produced per hour, 100 per cent acid basis).

n = Number of test runs.

(d) If applicable, the person must determine the destruction efficiency for each N_2O abatement technology according to paragraphs (d)(1), (d)(2), or (d)(3) of this section.

(1) Use the manufacturer's specified destruction efficiency.

(2) Estimate the destruction efficiency through process knowledge. Examples of information that could constitute process knowledge include calculations based on material balances, process stoichiometry, or previous test results provided the results are still relevant to the current vent stream conditions. The person must document how process knowledge (if applicable) was used to determine the destruction efficiency.

(3) Calculate the destruction efficiency by conducting an additional performance test on the emissions stream following the N_2O abatement technology.

(e) If applicable, the person must determine the abatement factor for each N_2O abatement technology. The abatement factor is calculated for each nitric acid train according to Equation 310-2 of this section.

$$AF_{Nt} = \frac{P_{at\,Abate}}{P_{at}}$$

Equation 310-2

Where:

AF_{Nt} = Abatement factor of N_2O abatement technology at nitric acid train "t" (fraction of annual production that abatement technology is operating).

P_{at} = Total annual nitric acid production from nitric acid train "t" (tonne acid produced, 100 per cent acid basis).

$P_{at\ Abate}$ = Annual nitric acid production from nitric acid train "t" during which N_2O abatement was used (tonne acid produced, 100 per cent acid basis).

(f) The person must determine the annual amount of nitric acid produced and the annual amount of nitric acid produced while each N_2O abatement technology is operating from each nitric acid train (100 per cent basis).

(g) The person must calculate N_2O emissions for each nitric acid train by multiplying the emissions factor (determined in Equation 310-1 of this section) by the annual nitric acid production and accounting for N_2O abatement, according to Equation 310-3 of this section:

$$E_{N_2Ot} = \sum_{N=1}^{z} \frac{EF_{N20t} * P_{at} * (1 - (DF_{Nt} * AF_{Nt}))}{1000} \qquad \textbf{Equation 310-3}$$

Where:

E_{N2Ot} = N_2O mass emissions per year for nitric acid train "t" (tonnes).

EF_{N2Ot} = Average site-specific N_2O emissions factor for nitric acid train "t" (kg N_2O generated/tonne acid produced, 100 per cent acid basis).

P_{at} = Annual nitric acid production from the train "t" (tonne acid produced, 100 per cent acid basis).

DF_{Nt} = Destruction efficiency of N_2O abatement technology N that is used on nitric acid train "t" (per cent of N_2O removed from air stream).

AF_{Nt} = Abatement factor of N_2O abatement technology for nitric acid train "t" (fraction of annual production that abatement technology is operating).

1000 = Conversion factor (kg/tonne).

z = Number of different N2O abatement technologies.

(h) The person must determine the annual nitric acid production emissions combined from all nitric acid trains at the facility using Equation 310-4 of this section:

$$N_2O = \sum_{t=1}^{m} E_{N2Ot} \qquad \textbf{Equation 310-4}$$

Where:

N_2O = Annual process N_2O emissions from nitric acid production facility (tonnes)

E_{N2Ot} = N_2O mass emissions per year for nitric acid train "t" (tonnes).

m = Number of nitric acid trains.

ON.314   Sampling, Analysis, and Measurement Requirements

(a) The person must conduct a new performance test and calculate a new site-specific emissions factor according to a test plan as specified in paragraphs (a)(1) through (a)(2) of this section.

   (1) Conduct the performance test annually.

   (2) Conduct the performance test when the nitric acid production process is changed, specifically when abatement equipment is installed.

(b) The person must measure the N_2O concentration during the performance test using one of the methods in paragraphs (b)(1) through (b)(3) of this section.

   (1) EPA Method 320 at 40 CFR part 63, appendix A, Measurement of Vapor Phase Organic and Inorganic Emissions by Extractive Fourier Transform Infrared (FTIR) Spectroscopy.

   (2) ASTM D6348 - Standard Test Method for Determination of Gaseous Compounds by Extractive Direct Interface Fourier Transform Infrared (FTIR) Spectroscopy.

   (3) An equivalent method, with Director approval in writing.

(c) The person must determine the production rate(s) (100 per cent basis) from each nitric acid train during the performance test according to paragraphs (c)(1) or (c)(2) of this section.

   (1) Direct measurement of production and concentration (such as using flow meters, weigh scales, for production and concentration measurements).

   (2) Existing plant procedures used for accounting purposes (i.e. dedicated tank-level and acid concentration measurements).

(d) The person must conduct all performance tests in conjunction with the applicable methods. For each test, the facility must prepare an emission factor determination report that must include the items in paragraphs (d)(1) through (d)(3) of this section.

   (1) Analysis of samples, determination of emissions, and raw data.

   (2) All information and data used to derive the emissions factor(s).

   (3) The production rate during each test and how it was determined.

(e) The person must determine the monthly nitric acid production and the monthly nitric acid production during which N_2O abatement technology is operating from each nitric acid train according to the methods in paragraphs (c)(1) or (c)(2) of this section.

(f) The person must determine the annual nitric acid production and the annual nitric acid production during which N_2O abatement technology is operating for each train by summing the respective monthly nitric acid production quantities

ON.315   Procedures for Estimating Missing Data

The person is required to retain a complete record of all measured parameters used in the GHG emissions calculations. Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter shall be used in the calculations as specified in paragraphs (a) and (b) of this section.

(a) For each missing value of nitric acid production, the substitute data shall be the best available estimate based on all available process data or data used for accounting purposes (such as purchase records).

(b) For missing values related to the performance test, including emission factors, production rate, and N_2O concentration, the person must conduct a new performance test according to the procedures in ON.314 (a) through (d).

ON.300 Petrochemical Production

ON.301 Source Definition

(a) The petrochemical production source consists of any facility that manufacturers petrochemicals, including acrylonitrile, carbon black, propylene, ethylene, ethylene dichloride, ethylene oxide, or methanol, from feedstocks derived from petroleum, or petroleum and natural gas liquids.

(b) A process that produces a petrochemical as a byproduct is not part of the petrochemical production source.

(c) A facility that makes methanol, hydrogen, and/or ammonia from synthesis gas should report under this section if the annual mass of methanol produced exceeds the individual annual mass production levels of both hydrogen recovered as product and ammonia. The facility should report under ON.100 (Hydrogen Production) if the annual mass of hydrogen recovered as product exceeds the individual annual mass production levels of both methanol and ammonia. The facility should report under ON.80 (Ammonia Manufacturing) if the annual mass of ammonia produced exceeds the individual annual mass production levels of both hydrogen recovered as product and methanol.

(d) A direct chlorination process that is operated independently of an oxychlorination process to produce ethylene dichloride is not part of the petrochemical production source.

(e) A process that produces a petrochemical from bio-based feedstock is not part of the petrochemical production source.

ON.302 Greenhouse Gas Reporting Requirements

For the purpose of Section 6 of the Regulation the annual emissions data report for petrochemical manufacturing shall include the following information at the facility level calculated in accordance with this method. The person must report facility wide N_2O process emissions as required by this method.

(a) CO_2, N_2O, and CH_4 emissions from combustion of fuels in the stationary combustion units in tonnes, as specified in ON.20 (tonnes).

(b) CO_2, N_2O, and CH_4 emissions from flares or other combustion devices in tonnes using methods ON.303(a)(1), ON.303(a)(2) or ON.303(c).

(c) CO_2, N_2O, and CH_4 process emissions from vents in tonnes using method ON.303(a)(3).

(d) CO_2, N_2O, and CH_4 process emissions from equipment leaks in tonnes using method ON.303(a)(4).

(e) CO_2 process emissions in tonnes using method ON.303(b).

(f) CO_2, N_2O, and CH_4 process emissions from ethylene production facilities in tonnes using method ON.303(c).

(g) Annual consumption of feedstock by type for all feedstocks that result in GHG emissions in standard cubic meters for gases; kilolitres for and liquids and tonnes for solid fuels.

ON.303   Calculation of GHG Emissions

Calculate GHG emissions using one of the methods in paragraphs (a), (b), or (c):

(a) <u>Method 1:</u> Calculate the GHG emissions from petrochemical production processes using the methods specific in paragraphs (a)(1) through (a)(3) of this section.

   (1) For flares, calculate CO_2, CH_4 and N_2O emissions using the methods specified in ON.200.

   (2) For combustion devices other than flares, calculate CO_2, CH_4 and N_2O emissions resulting from the combustion of fuels and process off-gas as specified in paragraphs (a)(2)(i) through (a)(2)(iii):

      (i)   Calculate CO_2 emissions from fuels and process off-gas in accordance with the methods in specified in ON.23.

      (ii)   Calculate CH_4 and N_2O emissions from combustion of fuels using the applicable methods in ON.24. Use the appropriate default emission factors for CH_4 and N_2O from Tables 20-2, 20-4, 20-6, and 20-7.

      (iii) Calculate CH_4 and N_2O emissions from process off-gas using the applicable equation 20-12 in ON.24 and the default emission factors of 2.8×10^{-3} kg/GJ for CH_4 and 5.7×10^{-4} kg/GJ for N_2O.

   (3) Calculate the emissions from process vents using the method specified in ON.203(b) for each process vent that can be reasonably expected to contain greater than 2 per cent by volume CO_2 or greater than 0.5 per cent by volume of CH_4 or greater than 0.01 per cent by volume (100 parts per million) of N_2O.

   (4) Calculate the emissions from equipment leaks using the method specified in ON.203(h)(1).

(b) <u>Method 2:</u> Calculate the emissions of CO_2 from each process unit, for each calendar month as described in paragraphs (b)(1) through (b)(5) of this section.

   (1) For each gaseous and liquid feedstock and product, measure the volume or mass used or produced each calendar month with a flow meter. Alternatively, for liquids, the person may calculate the volume used or collected in each month based on measurements of the liquid level in a storage tank at least once per month (and just prior to each change in direction of the level of the liquid). Fuels used for combustion purposes are not considered to be feedstocks. The emissions from the combustion of fuels (other than process off-gas) must be calculated in accordance with the methods specified in ON.23 for CO_2 and the methods specified in ON.24 for CH_4 and N_2O.

   (2) For each solid feedstock and product, measure the mass used or produced each calendar month.

(3) Collect a sample of each feedstock and product at least once per month and determine the carbon content of each sample. Alternatively, the person may use the results of analyses conducted by a fuel or feedstock supplier, provided the sampling and analysis is conducted at least once per month. If multiple valid carbon content measurements are made during the monthly measurement period, average them arithmetically.

(4) If the person determine that the monthly average concentration of a specific compound in a feedstock or product is greater than 99.5 per cent by volume (or mass for liquids and solids), then as an alternative to the sampling and analysis specified in paragraph (b)(3) of this section, the person may calculate the carbon content assuming 100 per cent of that feedstock or product is the specific compound during periods of normal operation. The person must maintain records of any determination made in accordance with this paragraph (b)(4) along with all supporting data, calculations, and other information. This alternative may not be used for products during periods of operation when off-specification product is produced. The person must reevaluate determinations made under this paragraph (b)(4) after any process change that affects the feedstock or product composition. The person must keep records of the process change and the corresponding composition determinations. If the feedstock or product composition changes so that the average monthly concentration falls below 99.5 per cent, the person is no longer permitted to use this alternative method.

(5) Calculate the CO_2 mass emissions for each petrochemical process unit using Equations 300-2 through 300-5 of this section.

(i) Gaseous feedstocks and products. Use Equation 300-1 of this section to calculate the net annual carbon input or output from gaseous feedstocks and products. Note that the result will be a negative value if there are no gaseous feedstocks in the process but there are gaseous products.

$$C_g = \sum_{n=1}^{12} [\sum_{i=1}^{j \ or \ k} [(F_{gf})_{i,n} * (CC_{gf})_{i,n} * \frac{(MW_f)_i}{MVC} - (P_{gp})_{i,n} * (CC_{gp})_{i,n} * \frac{(MW_p)_i}{MVC}]]$$

Equation 300-1

Where:

C_g = Annual net contribution to calculated emissions from carbon (C) in gaseous materials (kg/yr).

$(F_{gf})_{i,n}$ = Volume of gaseous feedstock i introduced in month "n" (Rm^3) at reference temperature and pressure conditions as used by the facility. If a mass flow meter is used, measure the feedstock introduced in month n in kg and replace the term "$(MW_f)_i/MVC$" with "1".

$(CC_{gf})_{i,n}$ = Average carbon content of the gaseous feedstock i for month "n" (kg C per kg of feedstock).

$(MW_f)_i$ = Molecular weight of gaseous feedstock i (kg/kg-mole).

MVC   =   Molar volume conversion factor at the same reference conditions as the above $(F_{gf})_{i,n}$ (Rm^3/kg-mole).

            =   8.3145 * [273.16 + reference temperature in °C] / [reference pressure in kilopascal]

$(P_{gp})_{i,n}$ =   Volume of gaseous product i produced in month "n" (Rm^3) at the same reference conditions as the above $(F_{gf})_{i,n}$. If a mass flow meter is used, measure the gaseous product produced in month "n" in kg and replace the term "$(MW_p)_i$/MVC" with "1".

$(CC_{gp})_{i,n}$ =   Average carbon content of gaseous product i, including streams containing CO_2 recovered for sale or use in another process, for month "n" (kg C per kg of product).

$(MW_p)_i$ =   Molecular weight of gaseous product i (kg/kg-mole).

j   =   Number of feedstocks.

k   =   Number of products.

    (ii) Liquid feedstocks and products. Use Equation 300-2 of this section to calculate the net carbon input or output from liquid feedstocks and products. Note that the result will be a negative value if there are no liquid feedstocks in the process but there are liquid products.

$$C_l = \sum_{n=1}^{12} \left[\sum_{i=1}^{j\,or\,k} \left[(F_{lf})_{i,n} * (CC_{lf})_{i,n} - (P_{lp})_{i,n} * (CC_{lp})_{i,n} \right] \right] \qquad \textbf{Equation 300-2}$$

Where:

C_l =   Annual net contribution to calculated emissions from carbon in liquid materials, including liquid organic wastes (kg/yr).

$(F_{lf})_{i,n}$ =   Volume or mass of liquid feedstock i introduced in month "n" (m^3 of feedstock). If a mass flow meter is used, measure the liquid feedstock in month "n" introduced in kg and measure the carbon content of feedstock in kg of C per kg of feedstock.

$(CC_{lf})_{i,n}$ =   Average carbon content of liquid feedstock i for month "n" (kg of C per m^3 of feedstock when feedstock usage is measured in m^3, or kg of C per kg of feedstock when feedstock usage is measured in kg).

$(P_{lp})_{i,n}$ =   Volume or mass of liquid product i produced in month "n" (m^3). If a mass flow meter is used, measure the liquid product produced in kg and measure the carbon content of liquid product in kg of C per kg of product.

$(CC_{lp})_{i,n}$ =   Average carbon content of liquid product i, including organic liquid wastes, for month "n" (kg of C per m^3 of product when liquid product is measured in m^3, or kg of C per kg of product when product is measured in kg)

j   =   Number of feedstocks.

k   =   Number of products.

(iii) Solid feedstocks and products. Use Equation 300-3 of this section to calculate the net annual carbon input or output from solid feedstocks and products. Note that the result will be a negative value if there are no solid feedstocks in the process but there are solid products.

$$C_s = \sum_{n=1}^{12} \left\{ \sum_{i=1}^{j\ or\ k} \left[\left(F_{sf}\right)_{i,n} * \left(CC_{sf}\right)_{i,n} - \left(P_{sp}\right)_{i,n} * \left(CC_{sp}\right)_{i,n} \right] \right\} \quad \textbf{Equation 300-3}$$

Where:

C_s = Annual net contribution to calculated emissions from carbon in solid materials (kg/yr).

$(F_{sf})_{i,n}$ = Mass of solid feedstock i introduced in month "n" (kg).

$(CC_{sf})_{i,n}$ = Average carbon content of solid feedstock i for month "n" (kg C per kg of feedstock).

$(P_{sp})_{i,n}$ = Mass of solid product i produced in month "n" (kg).

$(CC_{sp})_{i,n}$ = Average carbon content of solid product i in month "n" (kg C per kg of product).

j = Number of feedstocks.

k = Number of products.

(iv) Annual emissions. Use the results from Equations 300-1 through 300-3 of this section, as applicable, in Equation 300-4 of this section to calculate annual CO_2 emissions.

$$CO_2 = 0.001 * 3.664 * \left(C_g + C_l + C_s\right) \quad \textbf{Equation 300-4}$$

Where:

CO_2 = Annual CO_2 mass emissions from process operations and process off-gas combustion (tonnes/year).

0.001 = Conversion factor from kg to tonnes.

3.664 = Ratio of molecular weight, carbon dioxide to carbon.

(c) Method 3: (Optional combustion methodology for ethylene production processes) For ethylene production processes, calculate CO_2, CH_4, and N_2O emissions as specified in paragraphs (c)(1) and (c)(2):

(1) For each flare, calculate CO_2, CH_4, and N_2O emissions using the methodology for flares specified in ON.203(e).

(2) For all other combustion units, calculate the CO_2 emissions from combustion of fuel that contains ethylene process off-gas using either Calculation Methodologies 3 or 4 in ON.23(c) and (d), respectively. Calculate CH_4 and N_2O emissions using the applicable method in ON.24 and the emission factors of 2.8×10^{-3} kg/GJ for CH_4 and 5.7×10^{-4} kg/GJ for N_2O. The person is not required to use the same calculation methodology for each stationary combustion unit that burns ethylene process off-gas.

ON.304 Sampling, Analysis, and Measurement Requirements

(a) If the person calculate emissions using the method specified in ON.303(a):

(1) **Flares.** The person must comply with the monitoring requirements for flares specified in ON.204(e). The person may monitor the carbon content or the high heat value of the flares gas of flares in a petrochemical production facility on a quarterly basis.

(2) **Process Vents.** The person must comply with the monitoring requirements for process vents specified in ON.204(b).

(b) If the person calculates emissions using the method specified in ON.303(b):

(1) **Feedstock Consumption.** The person must measure the feedstock consumption using the same plant instruments used for accounting purposes, such as weigh hoppers, belt weigh feeders, or flow meters.

(2) **Product Production.** The person must measure the amount of product produced using the same plant instruments used for accounting purposes, such as weigh hoppers, belt weigh feeders, or flow meters.

(3) **Carbon Content.** Except as allowed by ON.303(b)(4), the carbon content of each feedstock and product must be measured at least once per month using one or more of the methods in Section 5 of the Guideline.

ON.305 Procedures for Estimating Missing Data

The person is required to retain a complete record of all measured parameters used in the GHG emissions calculations. Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter shall be used in the calculations as specified in paragraphs (a) or (b) of this section. The person must document and keep records of the procedures used for all such estimates as required by the Regulation.

(a) For each missing value of the carbon content and molecular weight, the substitute data value shall be the arithmetic average of the quality assured values of the parameter immediately preceding and immediately following the missing data incident. If no quality assured data is available prior to the missing data incident, the substitute data value shall be the first quality assured data value obtained after the missing data period.

(b) For missing feedstock and production values, the substitute data value shall be the best available estimate of the parameter, based on all available process data. The person must document and retain records of the procedures used for all such estimates.

ON.200   Petroleum Refining

ON.201   Source Definition

(a) A petroleum refining consists of all processes used to produce gasoline, aromatics, kerosene, distillate fuel oils, residual fuel oils, lubricants, asphalt, or other products through distillation of petroleum or through redistillation, cracking, rearrangement or reforming of unfinished petroleum derivatives.

(b) For the purposes of this method, facilities that distill only pipeline transmix (off-spec material created when different specification products mix during pipeline transportation) are not petroleum refineries, regardless of the products produced.

(c) This source consists of the following sources at petroleum refineries: catalytic cracking units; fluid coking units; delayed coking units; catalytic reforming units; coke calcining units; asphalt blowing operations; blowdown systems; storage tanks; process equipment components (compressors, pumps, valves, pressure relief devices, flanges, and connectors) in gas service; marine vessel, barge, tanker truck, and similar loading operations; flares; sulphur recovery plants; and non-merchant hydrogen plants (i.e., hydrogen plants that are owned or under the direct control of the refinery owner and operator).

ON.202   Greenhouse Gas Reporting Requirements

For the purpose of Section 6 of the Regulation the annual emissions data report for petroleum refining shall include the following information at the facility level calculated in accordance with this method:

(a) Catalyst Regeneration. Report CO_2, CH_4, and N_2O emissions.

(b) Process Vents. Report CO_2, N_2O, and CH_4 emissions.

(c) Asphalt Production. Report CO_2 and CH_4 emissions.

(d) Sulphur Recovery. Report CO_2 emissions.

(e) Flares and Other Control Devices. Report CO_2, N_2O, and CH_4 emissions.

(f) Above-Ground Storage Tanks. Report CH_4 emissions.

(g) Wastewater Treatment. Report CH_4 and N_2O emissions from anaerobic treatment.

(h) Oil-water Separators. Report CH_4 emissions from oil-water separators.

(i) Equipment Leaks. Report CH_4 emissions.

(j) Coke calcining units. Report CO_2, N_2O, and CH_4 emissions.

(k) Uncontrolled blowdown systems. Report CH_4 emissions.

(l) Loading Operations. Report CH_4 emissions.

(m) Delayed Coking Units. Report CH_4 emissions.

(n) Stationary Combustion Units Other than Flares and Control Devices. Report CO_2, N_2O, and CH_4 emissions as specified in ON.30 for combustion of refinery fuel gas, still gas, flexigas, or associated gas and ON.20 for combustion of all other fuels.

(o) Feedstock Consumption: Report feedstock consumption by type for all feedstocks which result in GHG emissions in the reporting year (including petroleum coke) in units of cubic metres for gases, kilolitres for liquids tonnes for non-biomass solids, and bone dry tonnes for biomass-derived solid fuels.

(p) Fuel Consumption: Report fuel consumption by fuel type consumed in the reporting year in units of cubic metres for gases, kilolitres for liquids, tonnes for non-biomass solids, and bone dry tonnes for biomass-derived solid fuels.

ON.203   Calculation of Greenhouse Gas Emissions

The person shall calculate GHG emissions using the methods in paragraphs (a) through (i) of this section. If a continuous emissions monitor is used to measure CO_2 emissions from process vents, asphalt production, sulphur recovery, or other control devices then the operator shall calculate the CO_2 emissions from these processes using a continuous emissions monitoring system (CEMS) as specified in ON.23(d). When the flue gas from two or more processes or stationary combustion sources are discharged through a common stack or duct before exiting to the atmosphere and if CEMS as specified in ON.23(d) are used to continuously monitor the CO_2 emissions, a person may report the combined emissions from the processes or stationary combustion sources sharing the common stack or duct instead of separately reporting the GHG emission from individual processes or stationary combustion sources.

(a) Catalyst Regeneration. The person shall calculate the CO_2, CH_4, and N_2O process emissions resulting from catalyst regeneration using the methods in paragraph (a)(1), (a)(2) and (a)(3), respectively.

(1) For units equipped with CEMS, the person shall calculate CO_2 process emissions resulting from catalyst regeneration using CEMS in accordance with ON.23(d). In the absence of CEMS data, the person shall use the methods in paragraphs (a)(1)(A) through (a)(1)(C).

(A) (i)   The person shall calculate process CO_2 emissions from the continuous regeneration of catalyst material in fluid catalytic cracking units (FCCU) and fluid cokers using Equations 200-1, 200-1b, 200-2, and 200-3 in section (a)(1)(A)(ii) below.

$$CO_2 = \sum_{i=1}^{n} CR_i \times CF \times 3.664 \times 0.001 \qquad \textbf{Equation 200-1}$$

Where:
CO_2 = CO_2 emissions (tonnes/yr)
n   =   number of hours of operation in the report year
CR_i =   hourly coke burn rate in kg/ hr
CF   =   carbon fraction in coke burned

3.664   =   ratio of molecular weights, carbon dioxide to carbon
0.001   =   conversion factor from kg to tonnes

   (ii) Alternatively, the person may calculate process CO_2 emissions from the continuous regeneration of catalyst material in fluid catalytic cracking units (FCCU) and fluid cokers using Equations 200-1b and 200-2.

$$CO_2 = \sum_{p=1}^{n} \left[(Q_r)_p \times \frac{(\%CO_2 + \%CO)_p}{100\%} \times \frac{44}{MVC} \times 0.001 \right] \qquad \textbf{Equation 200-1b}$$

Where:

CO_2	=	CO_2 emissions (tonnes/yr)
Q_r	=	volumetric flow rate of exhaust gas before entering the emission control system using equation 200-2 and at reference temperature and pressure conditions as used by the facility (dRm^3/hr)
$\%CO_2$	=	average hourly CO_2 concentration in regenerator exhaust, per cent by volume – dry basis
$\%CO$	=	average hourly CO concentration in regenerator exhaust, per cent by volume – dry basis. When there is no post-combustion device, assume %CO to be zero.
44	=	molecular weight of CO_2 (kg/kg-mole)
MVC	=	molar volume conversion factor at the same reference conditions as the above Q_r (Rm^3/kg-mole)
	=	8.3145 * [273.16 + reference temperature in °C] / [reference pressure in kilopascal]
0.001	=	conversion factor from kg to tonnes
n	=	number of hours of operation in the report year

   (iii) Either continuously monitor the volumetric flow rate of exhaust gas from the fluid catalytic cracking unit regenerator or fluid coking unit burner prior to the combustion of other fossil fuels or calculate the volumetric flow rate of this exhaust gas stream using Equation 200-2 of this section.

$$Q_r = \frac{\left(79 * Q_a + (100 - \%O_{oxy}) * Q_{oxy}\right)}{100 - \%CO_2 - \%CO - \%O_2} \qquad \textbf{Equation 200-2}$$

Where:

Qr	=	volumetric flow rate of exhaust gas from regenerator before entering the emission control system at reference temperature and pressure conditions as used by the facility (dRm^3/min)

Q_a = volumetric flow rate of air to regenerator, as determined from control room instrumentation at reference temperature and pressure conditions used for Q_r (dRm^3/min)

$\%Q_{xy}$ = oxygen concentration in oxygen enriched air stream, per cent by volume – dry basis

Q_{oxy} = volumetric flow rate of O_2 enriched air to regenerator as determined from catalytic cracking unit control room instrumentation at reference temperature and pressure conditions used for Q_r (dRm^3/min)

$\%CO_2$ = carbon dioxide concentration in regenerator exhaust, per cent by volume – dry basis

$\%CO$ = CO concentration in regenerator exhaust, per cent by volume – dry basis. When no auxiliary fuel is burned and a continuous CO monitor is not required, assume %CO to be zero

$\%O_2$ = O_2 concentration in regenerator exhaust, per cent by volume – dry basis

(iv) Calculate the hourly coke burn rate using Equation 200-3 or from facility measurement or engineering estimate:

$$CR_i = K_1 Q_r \times (\%CO_2 + \%CO) + K_2 Q_a - K_3 Q_r \times \left[\%CO/2 + \%CO_2 + \%O_2 \right] + K_3 Q_{oxy} \times (\%O_{oxy})$$

Equation 200-3

Where:

CR_i = hourly coke burn rate in kg/ hr

K_1, K_2, K_3 = material balance and conversion factors (K_1, K_2, and K_3 from Table 200-1 or from facility measurement or engineering estimate

Q_r = volumetric flow rate of exhaust gas before entering the emission control system from equation 200-2 (dRm^3/min)

Q_a = volumetric flow rate of air to regenerator as determined from control room instrumentation at reference temperature and pressure conditions used in Q_r (dRm^3/min)

$\%CO_2$ = CO_2 concentration in regenerator exhaust, per cent by volume – dry basis

$\%CO$ = CO concentration in regenerator exhaust, per cent by volume – dry basis

$\%O_2$ = O_2 concentration in regenerator exhaust, per cent by volume – dry basis

Q_{oxy} = volumetric flow rate of O_2 enriched air to regenerator as determined from control room instrumentation at reference temperature and pressure conditions used in Q_r (dRm^3/min)

$\%O_{xy}$ = O_2 concentration in O_2 enriched air stream inlet to regenerator, per cent by volume – dry basis

(B) The person shall calculate process CO_2 emissions resulting from continuous catalyst regeneration in operations other than FCCUs and fluid cokers (e.g. catalytic reforming) using Equation 200-4.

$$CO_2 = CC_{irc} \times (CF_{spent} - CF_{regen}) \times H \times 3.664 \qquad \textbf{Equation 200-4}$$

Where:

CO_2	=	CO_2 emissions (tonnes/yr)
CC_{irc}	=	average catalyst regeneration rate (tonnes/hr)
CF_{spent}	=	weight carbon fraction on spent catalyst
CF_{regen}	=	weight carbon fraction on regenerated catalyst (default = 0)
H	=	hours regenerator was operational (hr/yr)
3.664	=	ratio of molecular weights, CO_2 to carbon

(C) The person shall calculate process CO_2 emissions resulting from periodic catalyst regeneration using Equations 200-5

$$CO_2 = \sum_{1}^{n} \left[(CB_Q)_n \times CC \times 3.664 \times 0.001 \right] \qquad \textbf{Equation 200-5}$$

Where:

CO_2	=	Annual CO_2 emissions (tonnes/year).
CBQ	=	Coke burn-off quantity per regeneration cycle from engineering estimates (kg coke/cycle).
n	=	Number of regeneration cycles in the calendar year.
CC	=	Carbon content of coke based on measurement or engineering estimate (kg C per kg coke); default = 0.94.
3.664	=	ratio of molecular weights, carbon dioxide to carbon
0.001	=	Conversion factor (tonne/kg).

(2) Calculate CH_4 emissions using either unit specific measurement data, a unit-specific emission factor based on a source test of the unit, or Equation 200-6 of this section.

$$CH_4 = \left(CO_2 * \frac{EmF_2}{EmF_1} \right) \qquad \textbf{Equation 200-6}$$

Where:

CH_4	=	Annual methane emissions from coke burn-off (tonnes CH_4/year).
CO_2	=	Emission rate of CO_2 from coke burn-off calculated in paragraph (a)(1) of this section, as applicable (tonnes/year).
EmF_1	=	Default CO_2 emission factor for petroleum coke of 97 kg CO_2/GJ
EmF_2	=	Default CH_4 emission factor of 2.8×10^{-3} kg CH_4/GJ.

(3) Calculate N_2O emissions using either unit specific measurement data, a unit-specific emission factor based on a source test of the unit, or Equation 200-7 of this section.

$$N_2O = \left(CO_2 * \frac{EmF_3}{EmF_1} \right)$$ **Equation 200-7**

Where:

N_2O =   Annual nitrous oxide emissions from coke burn-off (tonne N_2O/year).

CO_2 =   Emission rate of CO_2 from coke burn-off calculated in paragraphs (a)(1) of this section, as applicable (tonnes/year).

EmF_1 =   Default CO_2 emission factor for petroleum coke of 97 kg CO_2/GJ .

EmF_3 =   Default N_2O emission factor of 5.7×10^{-4} kg N_2O/GJ

(b) Process Vents. Except for process emissions reported under other requirements of this regulation, the person shall calculate process emissions of CO_2, CH_4, and N_2O from process vents using Equation 200-8 for each process vent that can be reasonably expected to contain greater than 2 per cent by volume CO_2 or greater than 0.5 per cent by volume of CH_4 or greater than 0.01 per cent by volume (100 parts per million) of N_2O.

Equation 200-8

$$E_x = \sum_{i=1}^{n} VR_i \times F_{xi} \times (MW_x / MVC) \times VT_i \times 0.001$$

Where:

E_x =   Annual emissions of x (tonnes/yr), where x = CO_2, N_2O, or CH_4

VR_i =   Average volumetric flow rate for venting event i from measurement data, process knowledge or engineering estimates at reference temperature and pressure conditions as used by the facility (Rm^3/unit time). If a mass flow meter is used, measure the flow rate in kg/unit time and replace the term "MW_x/MVC" with "1".

F_{xi} =   Molar fraction of x in vent gas stream during event i from measurement data, process knowledge or engineering estimates.

MW_x =   molecular weight of x (kg/kg-mole)

MVC   =   molar volume conversion factor at the same reference conditions as the above VR_i (Rm3/kg-mole).

     =   8.3145 * [273.16 + reference temperature in °C] / [reference pressure in kilopascal]

VT_i =   time duration of venting event i, in same units of time as VR_i

n   =   number of venting events in report year

0.001   =   conversion factor from kg to tonnes

(c) Asphalt Production. The person shall calculate CO_2 and CH_4 process emissions from asphalt blowing activities using either process vent method specified in paragraph (b)

or according to the applicable provisions in paragraphs (c)(1) and (c)(2) of this
section.

(1) For uncontrolled asphalt blowing operations or asphalt blowing operations
controlled by vapor scrubbing, calculate CO_2 and CH_4 emissions using Equations
200-9 and 200-10 of this section, respectively.

$$CO_2 = \left(Q_{AB} \times EF_{AB,CO2}\right)$$ **Equation 200-9**

Where:

CO_2 =   Annual CO_2 emissions from uncontrolled asphalt blowing (tonnes CO_2/year).

Q_{AB} =   Quantity of asphalt blown (million barrels per year, MMbbl/year).

$E_{FAB,CO2}$ =   Emission factor for CO_2 from uncontrolled asphalt blowing from facility-specific test data (tonnes CO_2/MMbbl asphalt blown); default = 1,100.

$$CH_4 = \left(Q_{AB} \times EF_{AB,CH4}\right)$$ **Equation 200-10**

Where:

CH_4 =   Annual methane emissions from uncontrolled asphalt blowing (tonnes CH_4/year).

Q_{AB} =   Quantity of asphalt blown (million barrels per year, MMbbl/year).

$EF_{AB,CH4}$ =   Emission factor for CH_4 from uncontrolled asphalt blowing from facility-specific test data (tonnes CH_4/MMbbl asphalt blown); default = 580.

(2) For asphalt blowing operations controlled by thermal oxidizer or flare, calculate
CO_2 and CH_4 emissions using Equations 200-11 and 200-12 of this section,
respectively, provided these emissions are not already included in the flare
emissions calculated in paragraph (e) of this section or in the stationary
combustion unit emissions required under ON.20.

$$CO_2 = 0.98 \times \left(Q_{AB} \times CEF_{AB} \times 3.664\right)$$ **Equation 200-11**

Where:

CO_2 =   Annual CO_2 emissions from controlled asphalt blowing (tonnes CO_2/year).

0.98   =   Assumed combustion efficiency of thermal oxidizer or flare.

Q_{AB} =   Quantity of asphalt blown (MMbbl/year).

CEF_{AB} =   Carbon emission factor from asphalt blowing from facility-specific test data (tonnes C/MMbbl asphalt blown); default = 2,750.

3.664   =   ratio of molecular weights, carbon dioxide to carbon

$$CH_4 = 0.02 \times \left(Q_{AB} \times EF_{AB,CH4} \right)$$ **Equation 200-12**

Where:

CH_4	=	Annual methane emissions from controlled asphalt blowing (tonnes CH_4/year).
0.02	=	Fraction of methane uncombusted in thermal oxidizer or flare based on assumed 98% combustion efficiency.
Q_{AB}	=	Quantity of asphalt blown (million barrels per year, MMbbl/year).
$EF_{AB,CH4}$	=	Emission factor for CH_4 from uncontrolled asphalt blowing from facility-specific test data (tonnes CH_4/MMbbl asphalt blown); default = 580.

(d) Sulphur Recovery. The person shall calculate CO_2 process emissions from sulphur recovery units (SRUs) using Equation 200-13. For the molar fraction (MF) of CO_2 in the sour gas, use either a default factor of 0.20, engineering estimates or a source specific molar fraction value derived from source tests conducted at least once per calendar year. The person shall submit a pretest plan to the Director in the first year of reporting. The source test procedures in that plan shall be repeated in each future year to update the source specific emission factors annually.

$$CO_2 = FR \times MW_{CO2} / MVC \times MF \times 0.001$$ **Equation 200-13**

Where:

CO_2	=	emissions of CO_2 (tonnes/yr)
FR	=	volumetric flow rate of acid gas to SRU at reference temperature and pressure conditions as used by the facility (Rm^3/year). If a mass flow meter is used, measure the acid gas flow in kg per year and replace the term "MW_{CO2}/MVC" with "1"
MW_{CO2}	=	molecular weight of CO_2 (44 kg/kg-mole)
MVC	=	molar volume conversion factor at the same reference conditions as the above FR (Rm3/kg-mole).
	=	8.3145 * [273.16 + reference temperature in °C] / [reference pressure in kilopascal]
MF	=	molar fraction (%) of CO_2 in sour gas based on measurement or engineering estimate (default MF = 20% expressed as 0.20)
0.001	=	conversion factor from kg to tonnes

(e) Flares and Other Control Devices.

  (1) The person shall calculate and report CO_2, CH_4 and N_2O emissions resulting from the combustion of flare pilot and purge gas using the appropriate method(s) specified in section ON.20.

  (2) The person shall calculate and report CO_2 emissions resulting from the combustion of hydrocarbons routed to flares for destruction as follows:

(i)   Heat value or carbon content measurement. If the person has a continuous higher heating value monitor or gas composition monitor on the flare or if the person monitors these parameters at least weekly, the person must use the measured heat value or carbon content value in calculating the CO_2 emissions from the flare using the applicable methods in paragraphs (e)(2)(i)(A) and (e)(2)(i)(B).

(A) If the person monitors gas composition, calculate the CO_2 emissions from the flare using Equation 200-14 of this section. If daily or more frequent measurement data is available, the person must use daily values when using Equation 200-14 of this section; otherwise, use weekly values.

$$CO_2 = 0.98 \times 0.001 \times \left(\sum_{p=1}^{n} \left[3.664 \times (Flare)_p \times \frac{(MW)_p}{MVC} \times (CC)_p \right] \right) \quad \textbf{Equation 200-14}$$

Where:

CO_2	=	Annual CO_2 emissions for a specific fuel type (tonnes/year).
0.98	=	Assumed combustion efficiency of a flare.
0.001	=	Conversion factor from kg to tonnes.
n	=	Number of measurement periods. The minimum value for n is 52 (for weekly measurements); the maximum value for n is 366 (for daily measurements during a leap year).
p	=	Measurement period index.
3.664	=	Ratio of molecular weights, carbon dioxide to carbon
$(Flare)_p$	=	Volume of flare gas combusted during measurement period at reference temperature and pressure conditions as used by the facility (Rm^3/period). If a mass flow meter is used, measure flare gas flow rate in kg/period and replace the term "$(MW)_p$/MVC" with "1".
$(MW)_p$	=	Average molecular weight of the flare gas combusted during measurement period (kg/kg-mole). If measurements are taken more frequently than daily, use the arithmetic average of measurement values within the day to calculate a daily average.
MVC	=	Molar volume conversion factor at the same reference conditions as the above $(Flare)_p$ (Rm^3/kg-mole).
	=	8.3145 * [273.16 + reference temperature in °C] / [reference pressure in kilopascal]
$(CC)_p$	=	Average carbon content of the flare gas combusted during measurement period (kg C per kg flare gas). If measurements are taken more frequently than daily, use the arithmetic average of measurement values within the day to calculate a daily average.

(B) If the person monitors heat content but do not monitor gas composition, calculate the CO_2 emissions from the flare using Equation 200-15 of this section. If daily or more frequent measurement data is available, the person

must use daily values when using Equation 200-15 of this section; otherwise, use weekly values.

$$CO_2 = 0.98 \times 0.001 \times \sum_{p=1}^{n} \left[(Flare)_p \times (HHV)_p \times EmF \right]$$ **Equation 200-15**

Where:

CO_2	=	Annual CO_2 emissions for a specific fuel type (tonnes/year).
0.98	=	Assumed combustion efficiency of a flare.
0.001	=	Conversion factor from kg to tonnes.
n	=	Number of measurement periods. The minimum value for n is 52 (for weekly measurements); the maximum value for n is 366 (for daily measurements during a leap year).
p	=	Measurement period index.
$(Flare)_p$	=	Volume of flare gas combusted during measurement period at reference temperature and pressure conditions as used by the facility (Rm^3/period). If a mass flow meter is used, the person must also measure molecular weight and convert the mass flow to a volumetric flow as follows: Flare[m^3] = Flare [kg] × MVC/$(MW)_p$, where MVC is the molar volume conversion factor at the same reference conditions as $(Flare)_p$ (Rm3/kg-mole) and $(MW)_p$ is the average molecular weight of the flare gas combusted during measurement period (kg/kg-mole).
	=	8.3145 * [273.16 + reference temperature in °C] / [reference pressure in kilopascal])
$(HHV)_p$	=	Higher heating value for the flare gas combusted during measurement period (GJ per Rm^3,). If measurements are taken more frequently than daily, use the arithmetic average of measurement values within the day to calculate a daily average.
EmF	=	Default CO_2 emission factor of 57 kilograms CO_2/GJ (HHV basis).

(ii) Alternative Method. For startup, shutdown, and malfunctions during which the person were unable to measure the parameters required by Equations 200-14 and 200-15 of this section, the person must determine the quantity of gas discharged to the flare separately for each start-up, shutdown, or malfunction, and calculate the CO_2 emissions as specified in paragraphs (e)(1)(ii)(A) of this section.

(A) For periods of start-up, shutdown, or malfunction, use engineering calculations and process knowledge to estimate the carbon content of the flared gas for each start-up, shutdown, or malfunction event.

(B) For the reporting of emissions from normal operation flares in the year 2011, the person may use the average heating value measured for the fuel gas for the heating value of the flare gas. If heating value is not measured, the heating value may be estimated from historic data or engineering

calculation. If the person is unable to use the methods in ON.203(e)(2)(i) in 2012 due to health or safety reasons, the person may use the alternate method in the subsection in 2012 if it is consented to in writing by the Director.

(C) Calculate the CO_2 emissions using Equation 200-16 of this section.

$$CO_2 = 0.98 \times 0.001 \times \left(\sum_{p=1}^{n} \left[3.664 \times (Flare_{SSM})_p \times \frac{(MW)_p}{MVC} \times (CC)_p \right] \right)$$ **Equation 200-16**

Where:

CO_2	=	Annual CO_2 emissions for a specific fuel type (tonnes/year).
0.98	=	Assumed combustion efficiency of a flare.
0.001	=	Conversion factor from kg to tonnes.
n	=	Number of start-up, shutdown, and malfunction events during the reporting year.
p	=	Start-up, shutdown, malfunction and other measurement period index.
$(Flare_{SSM})_p$ =		Volume of flare gas combusted during indexed start-up, shutdown, or malfunction event from engineering calculations, at reference temperature and pressure conditions as used by the facility (Rm^3/event). If a mass flow meter is used, measure the flare gas combusted in kg per event and replace the term "$(MW)_p$/MVC" with "1".
$(MW)_p$	=	Average molecular weight of the flare gas, from the analysis results or engineering calculations for the event (kg/kg-mole).
MVC	=	Molar volume conversion factor at the same reference conditions as the above $(Flare_{SSM})_p$ (Rm3/kg-mole).
	=	8.3145 * [273.16 + reference temperature in °C] / [reference pressure in kilopascal]
$(CC)_p$	=	Average carbon content of the flare gas, from analysis results or engineering calculations for the event (kg C per kg flare gas).
3.664	=	Ratio of molecular weights, carbon dioxide to carbon

(3) The person shall calculate and report CH_4 and N_2O emissions resulting from the combustion of hydrocarbons routed to flares for destruction using the methods specified in paragraphs (e)(3)(A) and (e)(3)(B):

(A) Calculate CH_4 using Equation 200-17 of this section.

$$CH_4 = \left(CO_2 \times \frac{EmF_{CH4}}{EmF} \right) + CO_2 \times \frac{0.02}{0.98} \times \frac{16}{44} \times f_{CH4}$$ **Equation 200-17**

Where:

CH_4	=	Annual methane emissions from flared gas (tonnes CH_4/year).

CO_2 =   Emission rate of CO_2 from flared gas calculated in paragraph (e)(1) and (e)(2) of this section (tonnes/year).

EmF_{CH4} =   Default CH_4 emission factor for Petroleum Products of 2.8×10^{-3} kg/GJ

EmF =   Default CO_2 emission factor for flare gas of 57 kilograms CO_2/GJ (HHV basis).

$0.02/0.98$ =   correction factor for flare combustion efficiency.

$16/44$ =   correction factor ratio of the molecular weight of CH_4 to CO_2

f_{CH4} =   Weight fraction of carbon in the flare gas prior to combustion that is contributed by methane from measurement values or engineering calculations (kg C in methane in flare gas/kg C in flare gas); default is 0.4.

(B) Calculate N_2O emissions using Equation 200-18 of this section.

$$N_2O = \left(CO_2 \times \frac{EmF_{N2O}}{EmF} \right)$$

Equation 200-18

Where:

N_2O =   Annual nitrous oxide emissions from flared gas (tonnes N_2O/year).

CO_2 =   Emission rate of CO_2 from flared gas calculated in paragraph (e)(1) and (e)(2) of this section (tonnes/year).

EmF_{N2O} =   Default N_2O emission factor for petroleum products of 5.7×10^{-4} kg/GJ.

EmF =   Default CO_2 emission factor for flare gas of 57 kilograms CO_2/GJ (HHV basis).

(4) The person who uses methods other than flares (e.g. incineration, combustion as a supplemental fuel in heaters or boilers) to destroy low Btu gases (e.g. coker flue gas, gases from vapor recovery systems, casing vents and product storage tanks) shall calculate CO_2 emissions using Equation 200-19. The person shall determine CCA and MWA quarterly using methods specified in ON.20 and use the annual average values of CCA and MWA to calculate CO_2 emissions.

$$CO_2 = GV_A \times CC_A \times MW_A / MVC \times 3.664 \times 0.001$$

Equation 200-19

Where:

CO_2 = CO_2 emissions (tonnes/year)

GV_A =   volume of gas A destroyed annually at reference temperature and pressure conditions as used by the facility (Rm^3/year). If a mass flow meter is used, measure the gas destroyed in kg and replace the term "MW_A/MVC" with "1".

CC_A =   carbon content of gas A (kg C/kg fuel)

MW_A =   molecular weight of gas A

MVC	=	molar volume conversion factor at the same reference conditions as the above GV_A (Rm3/kg-mole).
	=	8.3145 * [273.16 + reference temperature in °C] / [reference pressure in kilopascal]
3.664	=	ratio of molecular weights, carbon dioxide to carbon
0.001	=	conversion factor from kg to tonnes

(f) Storage Tanks. For storage tanks other than those processing unstabilized crude oil except as provided in paragraph (f)(3) of this section, calculate CH_4 emissions using the applicable methods in paragraphs (f)(1) and (f)(2) of this section.

(1) For storage tanks other than those processing unstabilized crude oil, the person must either calculate CH_4 emissions from storage tanks that have a vapor-phase methane concentration of 0.5 volume per cent or more using tank-specific methane composition data (from measurement data or product knowledge) and the AP-42 emission estimation methods provided in Section 7.1 of the AP-42: "Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources", including TANKS Model (Version 4.09D) or similar programs, or estimate CH_4 emissions from storage tanks using Equation 200-20 of this section.

$$CH_4 = \left(0.1 \times Q_{\text{Re}f}\right) \qquad \text{Equation 200-20}$$

Where:

CH_4	=	Annual methane emissions from storage tanks (tonnes/year).
0.1	=	Default emission factor for storage tanks (tonne CH_4/MMbbl).
Q_{Ref}	=	Quantity of crude oil plus the quantity of intermediate products received from off site that are processed at the facility (MMbbl/year).

(2) For storage tanks that process unstabilized crude oil, calculate CH_4 emissions from the storage of unstabilized crude oil using either tank-specific methane composition data (from measurement data or product knowledge) and direct measurement of the gas generation rate or by using Equation 200-21 of this section.

$$CH_4 = (995{,}000 \times Q_{un} \times \Delta P) \times MF_{CH4} \times \frac{16}{MVC} \times 0.001 \qquad \text{Equation 200-21}$$

Where:

CH_4	=	Annual methane emissions from storage tanks (tonnes/year).
Q_{un}	=	Quantity of unstabilized crude oil received at the facility (MMbbl/year).
ΔP	=	Pressure differential from the previous storage pressure to atmospheric pressure (pounds per square inch, psi).

MF_{CH4} =   Mole fraction of CH_4 in vent gas from the unstabilized crude oil storage tank from facility measurements (kg-mole CH_4/kg-mole gas); use 0.27 as a default if measurement data is not available.

995,000   =   Correlation Equation factor (cubic feet gas per MMbbl per psi)

16   =   Molecular weight of CH_4 (kg/kg-mole).

MVC   =   Molar volume conversion (849.5 cubic feet/kg-mole).

0.001   =   Conversion factor (tonne/kg).

(3) The person does not need to calculate CH_4 emissions from storage tanks that meet any of the following descriptions:

  (i)   Units permanently attached to conveyances such as trucks, trailers, rail cars, barges, or ships;

  (ii)   Pressure vessels designed to operate in excess of 204.9 kilopascals and without emissions to the atmosphere;

  (iii)   Bottoms receivers or sumps;

  (iv)   Vessels storing wastewater; or

  (v)   Reactor vessels associated with a manufacturing process unit.

(g) Industrial Wastewater Processing.

(1) The person shall calculate CH_4 emissions from anaerobic wastewater treatment (such as anaerobic reactor, digester, or lagoon) using Equation 200-22 or Equation 200-23.

$$CH_4 = Q \times COD_{qave} \times B \times MCF \times 0.001 \qquad \textbf{Equation 200-22}$$

$$CH_4 = Q \times BOD_{5qave} \times B \times MCF \times 0.001 \qquad \textbf{Equation 200-23}$$

Where:

CH_4 =   emission of methane (tonnes/yr)

Q =   volume of wastewater treated (m^3/yr)

COD_{qave} =   average of quarterly determinations of chemical oxygen demand of the wastewater (kg/m^3)

BOD_{5qave} =   average of quarterly determinations of five-day biochemical oxygen demand of the wastewater (kg/m^3)

B =   methane generation capacity (B = 0.25 kg CH_4/kg COD and 0.06 kg CH_4/kg BOD_5)

MCF   =   methane correction factor for anaerobic decay (0-1.0) from Table 200-2

0.001   =   conversion factor from kg to tonnes

(2) For anaerobic processes from which biogas is recovered and not emitted, the person must adjust the CH_4 emissions calculated in paragraph (g)(1) by the amount of CH_4 collected.

(3) The person shall calculate N$_2$O emissions from wastewater treatment using
Equation 200-24.

$$N_2O = Q \times N_{qave} \times EF_{N2O} \times 1.571 \times 0.001$$

Equation 200-24

Where:

N$_2$O	=	emissions of N$_2$O (tonnes/yr)
Q	=	volume of wastewater treated (m^3/yr)
N$_{qave}$	=	average of quarterly determinations of N in effluent (kg N/m^3)
EF$_{N2O}$	=	emission factor for N$_2$O from discharged wastewater (0.005 kg N$_2$O-N/kg N)
1.571	=	conversion factor – kg N$_2$O-N to kg N$_2$O
0.001	=	conversion factor from kg to tonnes

(h) Oil-Water Separators. The person shall calculate CH$_4$ emissions from oil-water
separators using Equation 200-25. For the CF$_{NMHC}$ conversion factor, the person shall
use either a default factor of 0.6 or species specific conversion factors determined by
analysis using a sampling and analysis methodology approved in writing by the
Director.

$$CH_4 = EF_{sep} \times V_{water} \times CF_{NMHC} \times 0.001$$

Equation 200-25

Where:

CH$_4$	=	emission of methane (tonnes/yr)
EF$_{sep}$	=	NMHC (non methane hydrocarbon) emission factor (kg/m^3) from Table 200-3.
V$_{water}$	=	volume of waste water treated by the separator (m^3/yr)
CF$_{NMHC}$	=	NMHC to CH$_4$ conversion factor
0.001	=	conversion factor from kg to tonnes

(i) Equipment leaks. Calculate CH$_4$ emissions using the method specified in either
paragraph (i)(1) or (i)(2) of this section.

(1) Use process-specific methane composition data (from measurement data or
process knowledge) and any of the emission estimation procedures provided in
the Protocol for Equipment Leak Emissions Estimates (EPA-453/R-95-017, NTIS
PB96-175401).

(2) Use Equation 200-26 of this section.

$$CH_4 = \left(0.4 \times N_{CD} + 0.2 \times N_{PU1} + 0.1 \times N_{PU2} + 4.3 \times N_{H2} + 6 \times N_{FGS}\right)$$ **Equation 200-26**

Where:

CH$_4$	=	Annual methane emissions from equipment leaks (tonnes/year)
N$_{CD}$	=	Number of atmospheric crude oil distillation columns at the facility.

N_{PU1} = Cumulative number of catalytic cracking units, coking units (delayed or fluid), hydrocracking, and full-range distillation columns (including depropanizer and debutanizer distillation columns) at the facility.

N_{PU2} = Cumulative number of hydrotreating/hydrorefining units, catalytic reforming units, and visbreaking units at the facility.

N_{H2} = Total number of hydrogen plants at the facility.

N_{FGS} = Total number of fuel gas systems at the facility.

(j) Coke Calcining. The person shall calculate GHG emissions according to the applicable provisions in paragraphs (j)(1) through (j)(3) of this section.

(1) If the person operates and maintains a CEMS that measures CO_2 emissions according to ON.20, the person must calculate and report CO_2 emissions for coke calcining by following the CEMS Calculation Methodology 4 specified in ON.23(d). If the coke calcining unit is not equipped with CEMS must either install a CEMS that complies with the CEMS requirements in ON.20, or follow the requirements of paragraph (j)(2) of this section.

(2) Calculate the CO_2 emissions from the coke calcining unit using Equation 200-27 of this section.

$$CO_2 = 3.664 \times \left(M_{in} \times CC_{GC} - (M_{out} + M_{dust}) \times CC_{MPC} \right) \qquad \textbf{Equation 200-27}$$

Where:

CO_2 = Annual CO_2 emissions (tonnes/year).

M_{in} = Annual mass of green coke fed to the coke calcining unit from facility records (tonnes/year).

CC_{GC} = Average mass fraction carbon content of green coke from facility measurement data (tonne carbon/tonne green coke).

M_{out} = Annual mass of marketable petroleum coke produced by the coke calcining unit from facility records (tonnes petroleum coke/year).

M_{dust} = Annual mass of petroleum coke dust collected in the dust collection system of the coke calcining unit from facility records (tonne petroleum coke dust/year)

CC_{MPC} = Average mass fraction carbon content of marketable petroleum coke produced by the coke calcining unit from facility measurement data (tonne carbon/tonne petroleum coke).

3.664 = ratio of molecular weights, carbon dioxide to carbon

(3) For all coke calcining units, use the CO_2 emissions from the coke calcining unit calculated in paragraphs (i)(1) or (i)(2), as applicable, and calculate CH_4 and N_2O using the following methods:

(i) Calculate CH_4 emissions using either unit specific measurement data, a unit-specific emission factor based on a source test of the unit, or Equation 200-28 of this section.

$$CH_4 = \left(CO_2 * \frac{EmF_2}{EmF_1} \right)$$ **Equation 200-28**

Where:

CH_4	=	Annual methane emissions (tonnes CH_4/year).
CO_2	=	Emission rate of CO_2 calculated in paragraphs (i)(1) and (i)(2) of this section, as applicable (tonnes/year).
EmF_1	=	Default CO_2 emission factor for petroleum coke (97.12 kg CO_2/GJ).
EmF_2	=	Default CH_4 emission factor of 2.8 x 10^{-3} kg CH_4/GJ.

(ii) Calculate N2O emissions using either unit specific measurement data, a unit-specific emission factor based on a source test of the unit, or Equation 200-29 of this section.

$$N_2O = \left(CO_2 * \frac{EmF_3}{EmF_1} \right)$$ **Equation 200-29**

Where:

N_2O	=	Annual nitrous oxide emissions (tonnes N_2O/year).
CO_2	=	Emission rate of CO_2 from paragraphs (i)(1) and (i)(2) of this section, as applicable (tonnes/year).
EmF_1	=	Default CO_2 emission factor for petroleum coke (97.12 kg CO_2/GJ)
EmF_3	=	Default N_2O emission factor of 5.7 x 10^{-4} kg N_2O/GJ).

(k) Uncontrolled Blowdown Systems. For uncontrolled blowdown systems, the person must use the methods for process vents in paragraph (b) of this section.

(l) Loading Operations. For crude oil, intermediate, or product loading operations for which the equilibrium vapor-phase concentration of methane is 0.5 volume per cent or more, calculate CH_4 emissions from loading operations using product-specific, vapor-phase methane composition data (from measurement data or process knowledge) and the emission estimation procedures provided in Section 5.2 of the AP-42: "Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources." For loading operations in which the equilibrium vapor-phase concentration of methane is less than 0.5 volume per cent, the person may assume zero methane emissions.

(m) Delayed coking units. Calculate the CH_4 emissions from the depressurization of the coking unit vessel (i.e., the "coke drum") to atmosphere using either of the methods provided in paragraphs (l)(1) or (l)(2), provided no water or steam is added to the vessel once it is vented to the atmosphere. The person must use the method in paragraph (l)(1) of this section if the person adds water or steam to the vessel after it is vented to the atmosphere.

(1) Use the process vent method in paragraph (b) of this section and also calculate the CH_4 emissions from the subsequent opening of the vessel for coke cutting operations using Equation 200-30 of this section. If the person has coke drums or vessels of different dimensions, use Equation 200-30 for each set of coke drums or vessels of the same size and sum the resultant emissions across each set of coke drums or vessels to calculate the CH_4 emissions for all delayed coking units.

$$CH_4 = \left(N \times H \times \frac{(P_{CV} + 101.325)}{101.325} \times f_{void} \times \frac{\pi \times D^2}{4} \times \frac{16}{MVC} \times MF_{CH4} \times 0.001 \right)$$ **Equation 200-30**

Where:

CH_4	=	Annual methane emissions from the delayed coking unit vessel opening (tonnes/year).
N	=	Cumulative number of vessel openings for all delayed coking unit vessels of the same dimensions during the year.
H	=	Height of coking unit vessel (metres).
P_{CV}	=	Gauge pressure of the coking vessel when opened to the atmosphere prior to coke cutting or, if the alternative method provided in paragraph (l)(2) of this section is used, gauge pressure of the coking vessel when depressurization gases are first routed to the atmosphere (kilopascals)
101.325	=	Assumed atmospheric pressure (kilopascals, kPa)
f_{void}	=	Volumetric void fraction of coking vessel prior to steaming based on engineering judgment at reference temperature and pressure conditions as used by the facility (m^3 gas/m^3 of vessel);
D	=	Diameter of coking unit vessel (metres).
16	=	Molecular weight of CH_4 (kg/kg-mole).
MVC	=	Molar volume conversion factor at the same reference conditions as the cooking vessel (Rm^3/kg-mole).
	=	8.3145 * [273.16 + reference temperature in °C] / [reference pressure in kilopascal]
MF_{CH4}	=	Average mole fraction of methane in coking vessel gas based on the analysis of at least two samples per year, collected at least four months apart (kg-mole CH_4/kg-mole gas, wet basis);
0.001	=	Conversion factor from kg to tonne.

(2) Calculate the CH_4 emissions from the depressurization vent and subsequent opening of the vessel for coke cutting operations using Equation 200-18 of this section and the pressure of the coking vessel when the depressurization gases are first routed to the atmosphere. If the person has coke drums or vessels of different dimensions, use Equation 200-30 for each set of coke drums or vessels of the same size and sum the resultant emissions across each set of coke drums or vessels to calculate the CH_4 emissions for all delayed coking units.

ON.204   Sampling, Analysis, and Measurement Requirements

(a) Catalyst Regeneration.

    (1) For FCCUs and fluid coking units, the person shall measure the following parameters:

        (i) The daily oxygen concentration in the oxygen enriched air stream inlet to the regenerator.

        (ii) Continuous measurements of the volumetric flow rate of air and oxygen enriched air entering the regenerator.

        (iii) Weekly periodic measurements of the CO_2, CO and O_2 concentrations in the regenerator exhaust gas (or continuous measurements if the equipment necessary to make continuous measurements is already in place).

        (iv) Daily determinations of the carbon content of the coke burned.

        (v) The number of hours of operation.

        (vi) The measured daily or weekly values can be used to derive the minute or hourly parameters as required by the corresponding equations.

    (2) For periodic catalyst regeneration, the person shall measure the following parameters.

        (i) The mass of catalyst regenerated in each regeneration cycle.

        (ii) The weight fraction of carbon on the catalyst prior to and after catalyst regeneration.

    (3) For continuous catalyst regeneration in operations other than FCCUs and fluid cokers, the person shall measure the following parameters.

       The hourly catalyst regeneration rate.

        (i) The weight fraction of carbon on the catalyst prior to and after catalyst regeneration.

        (ii) The number of hours of operation.

(b) Process vents. The person shall measure the following parameters for each process vent.

    (1) The vent flow rate for each venting event from measurement data, process knowledge or engineering estimates.

    (2) The molar fraction of CO_2, N_2O, and CH_4 in the vent gas stream during each venting event from measurement data, process knowledge or engineering estimates.

    (3) The duration of each venting event.

(c) Asphalt Production. The person shall measure the mass of asphalt blown.

(d) Sulphur Recovery. The person shall measure the volumetric flow rate of acid gas to the SRU. If using source specific molar fraction that is based on measurements

instead of the default factor or engineering estimates, the person shall conduct an annual test of the molar fraction value.

(e) Flares and Other Control Devices. The person shall measure the following:

(1) If the person has a continuous flow monitor on the flare, the person must use the measured flow rates when the monitor is operational and the flow rate is within the calibrated range of the measurement device to calculate the flare gas flow. If the person does not have a continuous flow monitor on the flare and for periods when the monitor is not operational or the flow rate is outside the calibrated range of the measurement device, the person must use engineering calculations, company records, or similar estimates of volumetric flare gas flow.

(2) If using the method specified in ON.203(e)(2)(i)(A), monitor the carbon content of the flare gas daily if the flare is already equipped with the necessary measurement devices (at least weekly if not).

(3) If using the method specified in ON.203(e)(2)(i)(B), monitor the high heat value of the flare gas daily if the flare is already equipped with the necessary measurement devices (at least weekly if not).

(f) Storage Tanks. The person shall determine the annual throughput of crude oil, naphtha, distillate oil, asphalt, and gas oil for each storage tank using company record or applicable plant instruments.

(g) Wastewater Treatment. The person shall measure the following parameters.

(1) The person must collect samples representing wastewater influent to the anaerobic wastewater treatment process, following all preliminary and primary treatment steps (e.g., after grit removal, primary clarification, oil-water separation, dissolved air flotation, or similar solids and oil separation processes). The person must collect and analyze samples for COD or BOD_5 concentration once each calendar week.

(2) The person must measure the flow rate of wastewater entering anaerobic wastewater treatment process once each calendar week. The flow measurement location must correspond to the location used to collect samples analyzed for COD or BOD_5 concentration.

(3) The quarterly nitrogen content of the wastewater.

(h) Oil-Water Separators. The person shall measure the daily volume of waste water treated by the oil-water separators .

(i) Coke Calcining. Determine the mass of petroleum coke as required using measurement equipment used for accounting purposes including purchase records or direct measurement. Determine the carbon content of petroleum coke as using any one of the following methods:

(1) ASTM D3176 - Standard Practice for Ultimate Analysis of Coal and Coke.

(2) ASTM D5291 - Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants.

(3) ASTM D5373 - Standard Test Methods for Instrumental Determination of
Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal

ON.205   Procedures for Estimating Missing Data

The person is required to retain a complete record of all measured parameters used in the
GHG emissions calculations (e.g., concentrations, flow rates, fuel heating values, carbon
content values). Therefore, whenever a quality-assured value of a required parameter is
unavailable (e.g., if a CEMS malfunctions during unit operation or if a required fuel
sample is not taken), a substitute data value for the missing parameter shall be used in the
calculations.

(a) For stationary combustion sources, use the missing data procedures in ON.26.

(b) For each missing value of the heat content, carbon content, or molecular weight of the
fuel, substitute the arithmetic average of the quality-assured values of that parameter
immediately preceding and immediately following the missing data incident. If the
"after" value is not obtained by the end of the reporting year, the person may use the
"before" value for the missing data substitution. If, for a particular parameter, no
quality-assured data is available prior to the missing data incident, the substitute data
value shall be the first quality-assured value obtained after the missing data period.

(c) For missing CO_2, CO, O_2, CH_4, or N_2O concentrations, gas flow rate, and per cent
moisture, the substitute data values shall be the best available estimate(s) of the
parameter(s), based on all available process data (e.g., processing rates, operating
hours, etc.). The person shall document and keep records of the procedures used for
all such estimates as required by the Regulation.

Table 200-1.   Coke burn rate material balance and conversion factors

	(kg min)/(hr dRm^3%)	(lb min)/(hr dscf %)
K_1	0.2982	0.0186
K_2	2.0880	0.1303
K_3	0.0994	0.0062

K_1	Carbon burn term
K_2	Hydrogen burn term from O_2 in Air
K_3	Hydrogen burn equivalent in excess O_2 and carbon oxides

Table 200-2. Default MCF Values for Industrial Wastewater

Type of Treatment and Discharge Pathway or System	Comments	MCF	Range
Untreated			
Sea, river and lake discharge	Rivers with high organic loading may turn anaerobic, however this is not considered here	0.1	0 - 0.2
Treated			
Aerobic treatment plant	Well maintained, some CH_4 may be emitted from settling basins	0	0 – 0.1

Aerobic treatment plant	Not well maintained, overloaded	0.3	0.2 – 0.4
Anaerobic digester for sludge	CH_4 recovery not considered here	0.8	0.8 – 1.0
Anaerobic reactor	CH_4 recovery not considered here	0.8	0.8 – 1.0
Anaerobic shallow lagoon	Depth less than 2 metres	0.2	0 – 0.3
Anaerobic deep lagoon	Depth more than 2 metres	0.8	0.8 – 1.0

For CH_4 generation capacity (B) in kg CH_4/kg COD, use default factor of 0.25 kg CH_4/kg COD.

The emission factor for N_2O from discharged wastewater (EF_{N2O}) is 0.005 kg N_2O-N/kg-N.

MCF = methane conversion factor (the fraction of waste treated anaerobically).
COD = chemical oxygen demand (kg COD/m^3).

Table 200-3. Emission Factors for Oil/Water Separators

Separator Type	Emission factor (EF_{sep})[a] kg NMHC/m^3 wastewater treated
Gravity type – uncovered	1.11e-01
Gravity type – covered	3.30e-03
Gravity type – covered and connected to destruction device	0
DAF[b] of IAF[c] – uncovered	4.00e-03[d]
DAF or IAF – covered	1.20e-04[d]
DAF or Iaf – covered and connected to a destruction device	0

[a] EFs do not include ethane
[b] DAF = dissolved air flotation type
[c] IAF = induced air flotation device
[d] EFs for these types of separators apply where they are installed as secondary treatment systems

ON.200a   Petroleum Refineries

ON.201a   Source Category Definition

Source category definition as specified in ON.201.

The sources in this category may follow the reporting, calculation, sampling, analysis and measurement requirements of ON.203a, ON.204a , ON.203 or ON204 in 2011. For 2012 and any years after 2012, the person shall follow the requirements in ON.200.

ON.202a   Greenhouse Gas Reporting Requirements

For the purpose of Section 6 of the Regulation, the person may follow the annual emissions data reporting requirements in this section for the year 2011 for petroleum refineries, for one or more of the processes calculated in accordance this method:

a) Catalyst Regeneration. Report annual CO_2 emissions.

b) Process Vents. Report annual CO_2, N_2O, and CH_4 emissions.

c) Asphalt Production. Report annual CO_2 and CH_4 emissions.

d) Sulphur Recovery. Report annual CO_2 emissions.

e) Stationary Combustion Units Other than Flares and Control Devices. Report annual CO_2, N_2O, and CH_4 emissions as specified in ON.20.

f) Flares and Other Control Devices. Report annual CO_2, N_2O, and CH_4 emissions.

g) Above-Ground Storage Tanks. Report annual CH_4 emissions.

h) Wastewater Treatment. Report annual CH_4 and N_2O emissions.

i) Oil-Water Separators. Report annual CH_4 emissions.

j) Equipment Leaks. Report annual CH_4 emissions.

k) Feedstock Consumption: Report annual feedstock consumption by type for all feedstocks which result in GHG emissions in the reporting year (including petroleum coke) in units of standard cubic metres for gases, kilolitres for liquids, tonnes for non-biomass solids, and bone dry tonnes for biomass-derived solid fuels.

l) Fuel Consumption: Report annual fuel consumption by fuel type consumed in the reporting year in units of standard cubic metres for gases, kilolitres for liquids, tonnes for non-biomass solids, and bone dry tonnes for biomass-derived solid fuels.

ON.203a   Calculation of Greenhouse Gas Emissions

The person may calculate GHG emissions in 2011 using the methods in paragraphs (a) through (i) of this section. For 2012 and any subsequent year, the person shall calculate the GHG emission using the methods in ON.203.

a) Catalyst Regeneration. For units equipped with CEMS, the person shall calculate CO_2 process emissions resulting from catalyst regeneration using CEMS in accordance with Report EPS 1/PG/7. In the absence of CEMS data, the person shall use the methods in paragraphs (a)(1) through (a)(3).

(1) The person shall calculate process CO_2 emissions from the continuous regeneration of catalyst material in fluid catalytic cracking units (FCCU) and fluid cokers using Equations 200a-1, 200a-2, and 200a-3.

$$E_{CO_2} = \sum_{d=1}^{Y} CR_d \times CF \times 3.664 \times 0.001 \qquad \textbf{Equation 200a-1}$$

Where:

E_{CO2} = CO_2 emissions, tonnes/year

Y   =   Number of operating days in the year

CR_d =   Daily coke burn rate, calculated from equation 200a-2, kg/day

CF   =   Carbon fraction in coke burned

3.664   =   Ratio of molecular weights, carbon dioxide to carbon

0.001   =   Conversion factor from kilograms to tonnes

$$CR_d = \left[\sum_{i=1}^{H} [K_1 Q_r \times (\%CO_2 + \%CO) + K_2 Q_a - K_3 Q_r \times (\%CO/2 + \%CO_2 + \%O_2) + K_3 Q_{oxy} \times \%O_{oxy}]_i \right]$$

<div align="right">Equation 200a-2</div>

Where:

CR_d =   Daily coke burn rate, kg/day

H   =   Number of operating hours per day

K_1, K_2, K_3 =   Material balance and conversion factors (from Table 200a-1)

Q_r =   Volumetric flow rate of exhaust gas before entering the emission control system, calculated from equation 200a-3, D Sm^3/min

Q_a =   Volumetric flow rate of air to regenerator as determined from control room instrumentation, D Sm^3/min

% CO_2 basis   = CO_2 concentration in regenerator exhaust, percent by volume – dry

%CO basis   =   CO concentration in regenerator exhaust, percent by volume – dry

%O_2 basis   =   O2 concentration in regenerator exhaust, percent by volume – dry

Q_{oxy} = Volumetric flow rate of O_2 enriched air to regenerator as determined from control room instrumentation, D Sm^3/min

$\%O_{xy}$ = O2 concentration in O_2 enriched air stream inlet to regenerator, percent by volume – dry basis

$$Q_r = (79 \times Q_a + (100 - \%Q_{xy}) \times Q_{oxy})/(100 - \%CO_2 - \%CO - \%O_2)$$

Equation 200a-3

Where:

Q_r = Volumetric flow rate of exhaust gas from regenerator before entering the emission control system, D Sm^3/min

Q_a = Volumetric flow rate of air to regenerator, as determined from control room instrumentation, DSm^3/min

$\%Q_{xy}$ = Oxygen concentration in oxygen enriched air stream, percent by volume – dry basis

Q_{oxy} = Volumetric flow rate of O_2 enriched air to regenerator as determined from catalytic cracking unit control room instrumentation, DSm^3/min

$\%CO_2$ = Carbon dioxide concentration in regenerator exhaust, percent by volume – dry basis

$\%CO$ = CO concentration in regenerator exhaust, percent by volume – dry basis. When no auxiliary fuel is burned and a continuous CO monitor is not required, assume %CO to be zero

$\%O_2$ = O2 concentration in regenerator exhaust, percent by volume – dry basis

    (2) The person shall calculate process CO_2 emissions resulting from periodic catalyst regeneration using Equation 200a-4.

$$E_{CO_2} = \sum_{i=1}^{Y}[CRC \times (CF_{spent} - CF_{regen})]_i \times 3.664$$

Equation 200a-4

Where:

E_{CO2} = CO_2 emissions, tonnes /year

Y = Number of regeneration cycles

CRC = Mass of catalyst regenerated in the regeneration cycle, tonnes

CF_{spent} = Weight fraction of carbon in spent catalyst

CF_{regen} = Weight fraction of carbon in regenerated catalyst (default CF_{regen} = 0)

3.664 = Ratio of molecular weights, carbon dioxide to carbon

(3) The person shall calculate process CO_2 emissions resulting from continuous catalyst regeneration in operations other than FCCUs and fluid cokers (e.g. catalytic reforming) using Equation 200a-5.

$$E_{CO_2} = CRR \times (CF_{spent} - CF_{regen}) \times H \times 3.664$$

Equation 200a-5

Where:

E_{CO2} = CO_2 emissions, tonnes /year

CRR = Average catalyst regeneration rate, tonnes /hour

CF_{spent} = Weight fraction of carbon in spent catalyst

CF_{regen} = Weight fraction of carbon in regenerated catalyst (default CFregen = 0)

H = Number of hours regenerator was operational in the year

3.664 = Ratio of molecular weights, carbon dioxide to carbon

b) Process Vents. Except for process emissions reported under other requirements of the Guideline, the person shall calculate process emissions of CO_2, CH_4, and N_2O from process vents using Equation 200a-6.

$$E_x = \sum_{i=1}^{Y} VR_i \times F_{x,i} \times \rho_x \times VT_i \times 0.001$$

Equation 200a-6

Where:

E_x = Emissions of x (where x = CO_2, N_2O, or CH_4), tonnes /year

Y = Number of venting events

VR_i = Vent rate for venting event i, Sm^3/unit time

$F_{x,i}$ = Molar fraction of x in vent gas stream during venting event i

P_x = Density of x, kg/ Sm^3

VT_i = Time duration of venting event i (same unit of time used for VR_i)

0.001 = Conversion factor from kilograms to tonnes

c) Asphalt Production. The person shall calculate CH_4 and CO_2 process emissions from asphalt blowing activities using Equations 200a-7 and 200a-8.

$$E_{CH4} = (M_A \times EF \times \rho_{CH4}) \times (1 - \frac{DE}{100}) \times 0.001$$

Equation 200a-7

Where:

E_{CH4}	=	CH_4 emissions, tonnes /year
M_A	=	Mass of asphalt blown, 103 bbl/year
EF	=	Emission factor (default EF = 72.35), Sm^3 CH_4/103 bbl
ρ_{CH4}	=	Density of CH_4, kg/ Sm^3
DE	=	Control measure destruction efficiency, %
0.001	=	Conversion factor from kilograms to tonnes

$$E_{CO2} = (M_A \times EF \times \rho_{CH4}) \times \frac{DE}{100} \times 2.743 \times 0.001$$

Equation 200a-8

Where:

E_{CO2}	=	CO_2 emissions, tonnes /year
M_A	=	Mass of asphalt blown, 103 bbl/year
EF	=	Emission factor (default EF = 72.35), Sm^3 CH_4/103 bbl
ρ_{CH4}	=	Density of CH_4, kg/Sm^3
DE	=	Control measure destruction efficiency, %
2.743	=	Ratio of molecular weights, carbon dioxide to methane
0.001	=	Conversion factor from kilograms to tonnes

d) Sulphur Recovery. The person shall calculate CO_2 process emissions from sulphur recovery units (SRUs) using Equation 200a-9. For the molecular fraction (MF) of CO_2 in the sour gas, use either a default factor of 0.20 or a source specific molecular fraction value derived from source tests. The person shall submit a pretest plan to the Director in the first year of reporting. The source test procedures in that plan shall be repeated in each future year to update the source specific emission factors annually

$$E_{CO_2} = FR \times MF \times \rho_{CO2} \times 0.001$$

Equation 200a-9

Where:

E_{CO2}	=	CO_2 emissions, tonnes /year
FR	=	Volumetric flow rate of acid gas to SRU, Sm^3/year
MF	=	Molecular fraction of CO_2 in sour gas (default MF = 0.2)
ρ_{CO2}	=	Density of CO_2, kg/Sm^3
0.001	=	Conversion factor from kilograms to tonnes

e) Flares and Other Control Devices.

(1) The person shall calculate and report CO_2, CH_4 and N_2O emissions resulting from the combustion of flare pilot using the appropriate method(s) specified in sections ON.20.

The person shall calculate and report CO_2 emissions resulting from the combustion of hydrocarbons routed to flares for destruction as follows:

(A) Use Equation 200a-10 if the flare is equipped with a continuous flow and high heat value monitors:

$$E_{CO_2} = Flare \times HHV \times (EmF \times 0.001)$$ **Equation 200a-10**

Where:

E_{CO2}	=	CO_2 emissions, tonnes /year
Flare	=	Volume of flare gas, Sm^3/year
HHV	=	High heat value for refinery fuel or flare gas, GJ/Sm^3
EmF	=	CO_2 emission factor (default EmF = 57.6), kg/GJ
0.001	=	Conversion factor from kilograms to tonnes

(B) Use Equation 200a-11 if the flare is equipped with a continuous flow and carbon content monitors:

$$E_{CO_2} = Flare \ \times CC \times \rho \ \times 3.664 \times 0.001$$
Equation 200a-11

Where:

E_{CO2}	=	CO_2 emissions, tonnes /year

Flare $\quad=\quad$ Volume of flare gas, Sm^3/year

CC $\quad=\quad$ Carbon content of flare gas, kg C/kg fuel

ρ $\quad=\quad$ Density of flare gas, kg/Sm^3

3.664 $\quad=\quad$ Ratio of molecular weights, carbon dioxide to carbon

0.001 $\quad=\quad$ Conversion factor from kilograms to tonnes

(C) Use Equation 200a-12 if the flare is not equipped with a continuous flow monitor and HHV or carbon content monitor:

$$E_{CO_2} = RFT \times EF_{NMHC} \times CF_{NMHC} \times 3.664 \times 0.001$$

Equation 200a-12

Where:

E_{CO2} $\quad=\quad$ CO_2 emissions, tonnes /year

RFT $\quad=\quad$ Refinery feed input, Sm^3/year

EF_{NMHC} $\quad=\quad$ Non-methane hydrocarbon emission factor (default EFNMHC = 0.002), kg/ Sm^3 throughput

CF_{NMHC} $\quad=\quad$ Conversion factor from non-methane hydrocarbon to carbon (default CFNMHC= 0.6)

3.664 $\quad=\quad$ Ratio of molecular weights, carbon dioxide to carbon

0.001 $\quad=\quad$ Conversion factor from kilograms to tonnes

(2) The person who uses methods other than flares (e.g. incineration, combustion as a supplemental fuel in heaters or boilers) to destroy low heat content gases (e.g. coker flue gas, gases from vapor recovery systems, casing vents and product storage tanks) shall calculate CO_2 emissions using Equation 200a-13. The person shall determine CCA and MWA quarterly using methods specified in section ON.20 and use the annual average values of CCA and MWA to calculate CO_2 emissions.

$$E_{CO_2} = GV_i \times CC_i \times \rho_i \times 3.664 \times 0.001$$

Equation 200a-13

Where:

E_{CO2} $\quad=\quad$ CO_2 emissions from flare of gas i, tonnes /year

GV_i $\quad=\quad$ Volume of gas i destroyed annually, Sm^3/year

CC_i $\quad=\quad$ Carbon content of gas i, kg C/kg fuel

ρ_i =   Density of gas i, kg/Sm^3

3.664   =   Ratio of molecular weights, carbon dioxide to carbon

0.001   =   Conversion factor from kilograms to tonnes

f) Storage Tanks. For above-ground storage tanks containing crude oil, asphalt, naphtha, and distillate oils that are not equipped with vapor recovery technology, the person shall calculate CH$_4$ emissions using the U.S. EPA TANKS Model. For crude oil, naphtha, and distillate oils, use the default chemical databases for crude oil (RVP 5), distillate fuel oil No. 2, and jet naphtha (JP4), respectively. For asphalt, use the data in Table 200a-4 to create an asphalt chemical database. The annual throughput for each storage tank must be distributed equally across the twelve months of the year and the single-component liquid option selected. The total VOC emission values generated by the model shall be converted to methane emissions using:

(1) A default conversion factor of 0.6 (CH$_4$ = 0.6 * VOC); or Species specific conversion factors determined by storage tank headspace vapor analysis using a sampling and analysis methodology. The person shall submit the sampling and analysis methodology to the Director in the first year of reporting. The analysis shall be repeated in each future year to update the species specific conversion factors annually.

g) Wastewater Treatment.

(1) The person shall calculate CH$_4$ emissions from wastewater treatment using Equation 200a-14.

$$E_{CH_4} = [(Q \times COD_{qave}) - S] \times B \times MCF \times 0.001$$

Equation 200a-14

Where:

E$_{CH4}$ =   CH$_4$ emissions, tonnes/year

Q   =   Volume of wastewater treated, m3/year

COD$_{qave}$ =   Average of quarterly determinations of chemical oxygen demand of the wastewater, kg/m3

S   =   Organic component removed as sludge, kg COD/year

B   =   Methane generation capacity (default B = 0.25), kg CH$_4$/kg COD

MCF   =   Methane correction factor for anaerobic decay (0-1.0) from Table 200a-2

0.001   =   Conversion factor from kilograms to tonnes

(2) The person shall calculate N$_2$O emissions from wastewater treatment using Equation 200a-15.

$$E_{N_2O} = Q \times N_{qave} \times EF_{N2O} \times 1.571 \times 0.001$$

Equation 200a-15

Where:

E_{N2O}	=	N$_2$O emissions, tonnes/year
Q	=	Volume of wastewater treated, m3/year
N_{qave} N/m3	=	Average of quarterly determinations of nitrogen in effluent, kg N/m3
EF_{N2O}	=	Emission factor for N$_2$O from discharged wastewater (default $EF_{N2O} = 0.005$), kg N$_2$O -N/kg N
1.571	=	Conversion factor from kg N$_2$O -N to kg N$_2$O
0.001	=	Conversion factor from kilograms to tonnes

h) Oil-Water Separators. The person shall calculate CH$_4$ emissions from oil-water separators using Equation 200a-16. For the CFNMHC conversion factor, the person shall use either a default factor of 0.6 or species specific conversion factors determined by analysis using appropriate sampling and analysis methodology.   The person shall submit the sampling and analysis methodology to the Director in the first year of reporting. The analysis shall be repeated in each future year to update the conversion factor annually.

$$E_{CH_4} = EF_{sep} \times V_{water} \times CF_{NMHC} \times 0.001$$

Equation 200a-16

Where:

E_{CH4}	=	CH$_4$ emissions, tonnes/year
EF_{sep}	=	NMHC (non-methane hydrocarbon) emission factor from Table 200a-3, kg/m3.
V_{water}	=	Volume of waste water treated by the separator, m3/year
CF_{NMHC}	=	Conversion factor from NMHC to CH$_4$ (default $CF_{NMHC} = 0.6$)
0.001	=	Conversion factor from kilograms to tonnes

i) Equipment leaks. The person shall calculate CH$_4$ emissions for all components in natural gas, refinery fuel gas, and PSA off-gas systems as follows:

(1) Components shall be identified as one of the following classification types: valve, pump seal, connector, flange, open-ended line. The person shall use the method in CCME EPC-73: Environmental Code of Practice for the Measurement and Control of Fugitive VOC Emissions from Equipment Leaks (1993).   The

person shall conduct screenings at the frequency interval required by the Code of Practice.

(2) The volatile organic compounds (VOC) emissions shall be calculated using the following methods:

(A) For components where the measured screening value (SV) is indistinguishable from zero when corrected for background, the person shall calculate VOC emissions using Equation 200a-17:

$$VOC_{0,i} = CC_i \times Zf_{i0} \times t_i \qquad \textbf{Equation 200a-17}$$

Where:

$VOC_{0,i}$ = Zero component VOC emission for component type i, kg/screening period

i = Component type i (1 = valve, 2 = pump seal, 3 = other, 4 = connector, 5 = flange, 6 = open-ended line)

CC_i = Number of type i components where the screening value (SV) is 0

Zf_{i0} = Default zero factor for component type i from Table 200a-5, kg/hour

t_i = Time lapse since last screening for component type i, hours

(B) For leaking components, the person shall calculate VOC emissions using the following methods:

$$VOC_{LC,i} = \sum_{y=1}^{Y} \left(\sigma_i \times SV_y^{\beta i} \right) \times t_i \qquad \textbf{Equation 200a-18}$$

Where:

$VOC_{LC,i}$ = VOC emissions for component type i with SV between 0 to 10,000 ppmv, kg/screening period

i = Component type (1 = valve, 2 = pump seal, 3 = others, 4 = connector, 5 = flange, 6 = open ended-line)

Y = Number of type i components where the SV is between 0 to 10,000 ppmv

σ_i = Correlation equation coefficient for component type i from Table 200a-5

SV_y = Screening value for component y

β_i = Correlation equation exponent for component type i from Table 200a-5

t_i = Time duration for which the component has been leaking – default value is the time lapse since last screening, hours

$$VOC_{P,i} = CC_i \times PF_{iP-10} \times t_i$$

Equation 200a-19

Where:

$VOC_{P,i}$ = VOC emissions for component type i pegged over SV 9,999 ppmv, kg/screening period

i = Component type (1 = valve, 2 = pump seal, 3 = others, 4 = connector, 5 = flange, 6 = open-ended line)

CC_i = Number of type i components pegged over 9,999 ppmv

PF_{iP-10} = VOC emission factor for component type i pegged over 9,999 ppmv from Table 200a-5, kg/hour

t_i = Time duration for which the component has been leaking – default value is the time lapse since last screening, hours

   (C) The person shall calculate CH₄ emissions using Equation 200a-20. The person shall use system specific determinations of gas composition and methane content (refinery fuel gas, natural gas, associated gas, flexigas, low heat content gas), where available, to determine a CFVOC value. The person shall submit the sampling and analysis methodology to the Director in the first year of reporting. The analysis shall be repeated in each future year to update the conversion factor annually. When representative data is not available, the person shall use the default value of 0.6 for CFVOC.

$$CH_{4,i} = \sum_{y=1}^{Y} \left(VOC_{0,i} + VOC_{LC,i} + VOC_{P,i}\right)_y \times CF_{VOC} \times 0.001$$

Equation 200a-20

Where:

$CH_{4,i}$ = CH₄ emissions for component type i, tonnes/year

i = Component type (1 = valve, 2 = pump seal, 3 = others, 4 = connector, 5 = flange, 6 = open-ended line)

Y = Number of screenings per year for component type i

$VOC_{0,i}$ = Zero component VOC emissions for component type i, kg/screening period

$VOC_{LC,i}$ = VOC emissions for component i with SV between 0 to 10,000 ppmv, kg/screening period

$VOC_{P,i}$ = VOC emissions for component type i pegged over 9,999 ppmv, kg/screening period

CF_{VOC} = Conversion factor from volatile organic compounds to methane (default CFVOC=0.6)

0.001 = Conversion factor from kilograms to tonnes

ON.204a   Sampling, Analysis, and Measurement Requirements

The person may follow the sampling, analysis and measurement requirements of ON.204a , if they are using the calculation methods in ON.203a for calculating emissions in 2011. For 2012 and any subsequent year, the person shall follow the sampling, analysis and measurement requirements in ON.204.

a) Catalyst Regeneration

   (1) For FCCUs and fluid coking units, the person shall measure the following parametres:

      (A) The daily oxygen concentration in the oxygen enriched air stream inlet to the regenerator.
      (B) Continuous measurements of the volumetric flow rate of air and oxygen enriched air entering the regenerator.
      (C) Continuous or weekly periodic measurements of the CO_2, CO and O_2 concentrations in the regenerator exhaust gas, to be determined by individual jurisdictions.
      (D) Daily determinations of the carbon content of the coke burned
      (E) The number of days of operation.

   (2) For periodic catalyst regeneration, the person shall measure the following parameters.

      (A) The mass of catalyst regenerated in each regeneration cycle.
      (B) The weight fraction of carbon on the catalyst prior to and after catalyst regeneration.

   (3) For continuous catalyst regeneration in operations other than FCCUs and fluid cokers, the person shall measure the following parameters.

      (A) The hourly catalyst regeneration rate.
      (B) The weight fraction of carbon on the catalyst prior to and after catalyst regeneration.
      (C) The number of hours of operation.

b) Process vents. The person shall measure the following parameters for each process vent.

   (1) The vent flow rate for each venting event.

   (2) The molar fraction of CO_2, N_2O, and CH_4 in the vent gas stream during each venting event.

   (3) The duration of each venting event.

c) Asphalt Production. The person shall measure the mass of asphalt blown.

d) Sulphur Recovery. The person shall measure the volumetric flow rate of acid gas to the SRU. If using source specific molecular faction value instead of the default factor, the person shall conduct an annual test of the CO_2 content using appropriate methods.   The person shall submit a pretest plan to the Director in the first year of

reporting. The source test procedures in that plan shall be repeated in each future year to update the source specific emission factors annually.

e) Flares and Other Control Devices. The person shall measure the following:

(1) If using the method specified in ON.203a(e)(1)(A), monitor the flow rate and high heat value of the flare gas using continuous monitors.

(2) If using the method specified in ON.203a(e)(1)(B), monitor the flow rate and carbon content of the flare gas using continuous monitors.

(3) If using the method specified in ON.203a(e)(2), monitor the volume of gas destroyed annually (determined to accuracy of ± 7.5%) and the carbon content.

f) Storage Tanks. The person shall measure the annual throughput of crude oil, naphtha, distillate oil, asphalt, and gas oil for each storage tank using flow metres.

g) Wastewater Treatment. The person shall measure the following parameters.

(1) The daily volume of waste water treated.

(2) The quarterly chemical oxygen demand of the wastewater.

(3) The amount of sludge removed and the organic content of the sludge.

(4) The quarterly nitrogen content of the wastewater.

h) Oil-Water Separators. The person shall measure the daily volume of waste water treated by the oil-water separators.

i) Equipment Leaks. The person shall measure screening values for each valve, pump seal, connector, flange, and open-ended line used in natural gas, refinery fuel gas, and PSA off-gas systems using the methods specified in CCME EPC-73E: Environmental Code of Practice for the Measurement and Control of Fugitive VOC Emissions from Equipment Leaks (1993). The person shall conduct screenings at the frequency interval required by the Code of Practice.

Table 200a-1. Coke burn rate material balance and conversion factors

	$(kg \cdot min)/(hour \cdot DSm^3 \cdot \%)$
K_1	0.2982
K_2	2.0880
K_3	0.0994

Table 200a-2. Default MCF Values for Industrial Wastewater

Type of Treatment and Discharge Pathway or System	Comments	MCF	Range
Untreated			
Sea, river and lake discharge	Rivers with high organic loading may turn anaerobic, however this is not considered here	0.1	0 - 0.2
Treated			
Aerobic treatment plant	Well maintained, some CH_4 may be emitted from settling basins	0	0 – 0.1
Aerobic treatment plant	Not well maintained, overloaded	0.3	0.2 – 0.4
Anaerobic digester for sludge	CH_4 recovery not considered here	0.8	0.8 – 1.0
Anaerobic reactor	CH_4 recovery not considered here	0.8	0.8 – 1.0
Anaerobic shallow lagoon	Depth less than 2 metres	0.2	0 – 0.3
Anaerobic deep lagoon	Depth more than 2 metres	0.8	0.8 – 1.0
For CH_4 generation capacity (B) in kg CH_4/kg COD, use default factor of 0.25 kg CH_4/kg COD. The emission factor for N_2O from discharged wastewater (EF_{N2O}) is 0.005 kg N_2O-N/kg-N. MCF = methane conversion factor (the fraction of waste treated anaerobically). COD = chemical oxygen demand (kg COD/m^3).			

Table 200a-3. Emission Factors for Oil/Water Separators

Separator Type	Emission factor $(EF_{sep})^a$ kg NMHC/m^3 wastewater treated
Gravity type – uncovered	1.11×10^{-1}
Gravity type – covered	3.30×10^{-3}
Gravity type – covered and connected to destruction device	0
DAF^b of IAF^c – uncovered	4.00×10^{-3d}
DAF or IAF – covered	1.20×10^{-4d}
DAF or Iaf – covered and connected to a destruction device	0
[a] EFs do not include ethane [b] DAF = dissolved air flotation type [c] IAF = induced air flotation device [d] EFs for these types of separators apply where they are installed as secondary treatment systems	

Table 200a-4. Data for Preparing the Asphalt Chemical Database

Parametre	Database Entry
Liquid Molecular Weight	1000
Vapor Molecular Weight	105
Liquid Density (kg/m^3 at 15 ^{o}C)	969.7
Liquid Density (lb/gal. at 60 ^{o}F)	8.0925
Antoine's Equation Constants (using K)	A = 75350.06
	B = 9.00346

Table 200a-5. Fugitive Emissions from Gas Service Components

Component Type / Service Type	Default Zero Factor (kg/hour)	Correlation Equation (kg/hour)	Pegged Factor (kg/hour)
	(SV = 0) Zf_{i0}	(SV > 0 and < 10,000) σ_i and β_i	(SV > 9,999) PF_{iP-10}
1, Valves	7.8×10^{-6}	$2.27 \times 10^{-6}(SV)^{0.747}$	0.064
2, Pump seals	1.9×10^{-5}	$5.07 \times 10^{-5}(SV)^{0.622}$	0.089
3, Others[a]	4.0×10^{-6}	$8.69 \times 10^{-6}(SV)^{0.642}$	0.082
4, Connectors	7.5×10^{-6}	$1.53 \times 10^{-6}(SV)^{0.736}$	0.030
5, Flanges	3.1×10^{-7}	$4.53 \times 10^{-6}(SV)^{0.706}$	0.095
6, Open-ended lines	2.0×10^{-6}	$1.90 \times 10^{-6}(SV)^{0.724}$	0.033

[a] The "other" component type should be applied to any component type other than connectors, flanges, open-ended lines, pump seals, or valves. The "other" component type includes: instruments, loading arms, pressure relief valves, vents, compressors, dump lever arms, diaphragms, drains, hatches, metres, and polished rods stuffing boxes.

ON.340   Phosphoric acid Production

ON.341   Source Definition

The phosphoric acid production source consists of facilities with a wet-process phosphoric acid process line used to produce phosphoric acid. A wet-process phosphoric acid process line is the production unit or units identified by an individual identification number in an operating permit and/or any process unit or group of process units at a facility reacting phosphate rock from a common supply source with acid.

ON.342   Greenhouse Gas Reporting Requirements

For the purpose of Section 6 of the Regulation the annual emissions data report for phosphoric acid production shall include the following information at the facility level calculated in accordance with this method:

CO_2 process emissions from each wet-process phosphoric acid process line (tonnes).

Emissions of CO_2, CH_4, and N_2O from stationary combustion units not covered by this method shall follow the requirements of ON.20 (tonnes).

ON.343   Calculation of GHG Emissions

Quantify emissions in accordance with U.S. EPA 40 CFR 98 Subpart Z Section 98.263.

ON.344   Sampling, Analysis, and Measurement Requirements

Sampling, analysis and measurement requirements for this source shall be done in accordance with U.S. EPA 40 CFR 98 Subpart Z Section 98.264.

ON.345   Procedures for Estimating Missing Data

Missing data requirements for this source shall be estimated in accordance with U.S. EPA 40 CFR 98 Subpart Z Section 98.265.

ON.210   Pulp and Paper Manufacturing

ON.211   Source Definition

The pulp and paper manufacturing source consists of facilities that produce market pulp (i.e., stand-alone pulp facilities), manufacture pulp and paper (i.e., integrated facilities), produce paper products from purchased pulp, produce secondary fiber from recycled paper, convert paper into paperboard products (e.g., containers), or operate coating and laminating processes

ON.212   Greenhouse Gas Reporting Requirements

For the purpose of Section 6 of the Regulation the annual emissions data report for pulp and paper manufacturing shall include the following information at the facility level calculated in accordance with this method:

(a) Annual CO_2, biogenic CO_2, CH_4, and N_2O process emissions from all recovery units and kilns combined in tonnes, as specified in ON.213.

(b) Annual CO_2 emissions from addition of makeup chemicals (CaCO3, Na2CO3) in the chemical recovery areas of chemical pulp mills.

(c) CO_2 N_2O, and CH_4 emissions from electricity generation units in tonnes, as specified in ON.43. CO_2, N_2O, and CH_4 emissions from stationary combustion units in tonnes, as specified in ON.23 and ON.24.

(d) Annual consumption of carbonate in tonnes.

(e) Annual black liquor production in tonnes.

ON.213   Calculation of GHG Emissions

Calculate emissions from each unit (i.e., kraft or soda chemical recovery furnace, sulfite chemical recovery combustion unit, stand-alone semichemical recovery combustion unit, or kraft or soda pulp mill lime kiln) as specified under paragraphs (a) through (d) of this section. CH_4 and N_2O emissions must be calculated as the sum of emissions from combustion of fossil fuels and combustion of biomass in spent liquor solids.

(a) Calculate fossil-fuel based CO_2 emissions from direct measurement of fossil fuels consumed and the methodology for stationary combustion sources specified by ON.20 , or the methodology for electricity generation specified by WCI.43, for the appropriate fuel type. For kraft or soda pulp mill lime kilns, if ON.20 allows the use of default emission factors, use the default CO_2 emission factors listed in Table 210-1.

(b) Calculate fossil-fuel based CH_4 and N_2O emissions from direct measurement of fossil fuels consumed, default HHV, and default emission factors according to the methodology specified by ON.20 or WCI.43. For kraft or soda pulp mill lime kilns, use the default CH_4 and N_2O emission factors listed in Table 210-1.

(c) Calculate biogenic CO_2 emissions and emissions of CH_4 and N_2O from biomass as specified under subparagraphs (1) through (3).

(1) For kraft or soda chemical recovery furnaces, calculate emissions using Equation 210-1:

$$Emissions = Solids \times HHV \times EF$$

Equation 210-1

Where:

Emissions	=	Biogenic CO_2 emissions and emissions of CH_4 and N_2O from biomass (spent liquor solids) combustion (tonnes/year).
Solids	=	Mass of spent liquor solids combusted (tonnes/year).
HHV	=	Annual high heat value of spent liquor solids (mmBtu/kg).
EF	=	Default emission factor for CO_2, CH_4, and N_2O from Table 210-2 (kg/mmBtu)

(2) For sulfite or stand-alone semichemical chemical recovery combustion units, calculate CO_2 emissions using Equation 210-2:

$$E_{CO2} = 3.664 \times Solids \times CC$$

Equation 210-2

Where:

E_{CO2}	=	Biogenic CO_2 emissions from spent liquor solids combustion (tonnes/year).
3.664	=	Ratio of molecular weights, CO_2 to carbon.
Solids	=	Mass of spent liquor solids combusted (tonnes/year).
CC	=	Annual carbon content of spent liquor solids (per cent by weight, expressed as a decimal fraction).

(3) For sulfite or stand-alone semichemical chemical recovery combustion units, calculate emissions of CH_4 and N_2O from biomass using Equation 210-1.

(d) For make-up chemical use, calculate CO_2 emissions by using direct or indirect measurement of the quantity of chemicals added and ratios of the molecular weights of CO_2 and make-up chemicals using Equation 210-3:

$$CO_2 = \left(\left[M_{CaCO3} \times \frac{44}{100} \right] + \left[M_{Na2CO3} \times \frac{44}{105.99} \right] \right)$$

Equation 210-3

Where:

CO_2	=	CO_2 emissions from make-up chemicals (tonnes/year).
M_{CaCO3}	=	Make-up quantity of $CaCO_3$ used for reporting year (tonnes/year).
M_{Na2CO3}	=	Make-up quantity of Na_2CO_3 used for reporting year (tonnes/year).
44	=	Molecular weight of CO_2.
100	=	Molecular weight of $CaCO_3$.
106	=	Molecular weight of Na_2CO_3.

ON.214   Sampling, Analysis, and Measurement Requirements

At least annually, determine the following fuel properties. If measurements are performed more frequently than annually, then fuel properties must be based on the average of the representative measurements made during the year.

(a) Determine high heat values of black liquor using Technical Association of the Pulp and Paper Industry (TAPPI) T684 om-06 "Gross High Heating Value of Black Liquor".

(b) Determine annual mass of spent liquor solids using one of the methods specified in subparagraph (1) or (2)

   (1) Measure mass of annual spent liquor solids using TAPPI T650 om-05 "Solids Content of Black Liquor".

   (2) Determine mass of annual spent liquor solids based on records of measurements made with an online measurement system that determines the mass of spent liquor solids fired in a chemical recovery furnace or chemical recovery combustion unit. Measure the quantity of black liquor produced each month.

(c) Determine carbon content using ASTM D5373 - Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal, or ASTM 5291 - Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants.

ON.215   Procedures for Estimating Missing Data

The person is required to retain a complete record of all measured parameters used in the GHG emissions calculations. Therefore, whenever a quality-assured value of a required parameter is unavailable (e.g., if a meter malfunctions during unit operation or if a required sample is not taken), a substitute data value for the missing parameter shall be used in the calculations, according to the requirements of paragraphs (a) through (c) of this section:

(a) There are no missing data procedures for measurements of heat content and carbon content of spent pulping liquor. A re-test must be performed if the data from any annual measurements are determined to be invalid.

(b) For missing measurements of the mass of spent liquor solids or spent pulping liquor flow rates, use the lesser value of either the maximum mass or fuel flow rate for the combustion unit, or the maximum mass or flow rate that the fuel meter can measure.

(c) For the use of makeup chemicals (carbonates), the substitute data value shall be the best available estimate of makeup chemical consumption, based on available data (e.g., past accounting records, production rates). The person shall document and keep records of the procedures used for all such estimates as required by the Regulation.

Table 210-1 Kraft Lime Kiln and Calciner Emissions Factors for Fossil Fuel-Based CO_2, CH_4, and N_2O

| Fuel | Fossil Fuel-Based Emissions Factors (kg/mmBtu HHV) | | | | | |
| | Kraft Lime Kilns | | | Kraft Calciners | | |
	CO_2	CH_4	N_2O	CO_2	CH_4	N_2O
Residual Oil	76.7	0.0027	0	76.7	0.0027	0.0003
Distillate Oil	73.5			73.5		0.0004
Natural Gas	56.0			56.0		0.0001
Biogas	0			0		0.0001

Table 210-2 Kraft Pulping Liquor Emissions Factors for Biomass-Based CO_2, CH_4, and N_2O.

| Wood Furnish | Biomass-Based Emissions Factors (kg/mmBtu HHV) | | |
	CO_2[a]	CH_4	N_2O
North American Softwood	94.4	0.030	0.005
North American Hardwood	93.7		
Bagasse	95.5		
Bamboo	93.7		
Straw	95.1		

[a] Includes emissions from both the recovery furnace and pulp mill lime kiln.

ON.30   Refinery Fuel Gas Use within a Petroleum Refinery

ON.31   Source Definition

This source consists of any combustion device that is located at a petroleum refinery and that combusts refinery fuel gas, still gas, flexigas, or associated gas.

ON.32   Greenhouse Gas Reporting Requirements

For the purpose of Section 6 of the Regulation the annual emissions data report for refinery fuel gas combustion shall include the following information at the facility level calculated in accordance with this method:

(a) Annual CO_2, CH_4, and N_2O emissions from refinery fuel gas combustion in tonnes.

(b) Annual fuel consumption in units of standard cubic meters.

(c) Average carbon content of each fuel used to compute CO_2 emissions.

ON.33   Calculation of Greenhouse Gas Emissions

(a) Calculation of CO_2 Emissions. The person shall calculate daily CO_2 emissions for each fuel gas system using any of the methods specified in paragraphs (a)(1) through (a)(4) of this section. Calculate the total annual CO_2 emissions from combustion of all fuel gas by summing the CO_2 emissions from each fuel gas system.

(1) Use a CEMS that complies with the provisions in section ON.23(d).

(2) Calculate CO_2 emissions from each refinery fuel gas system and flexigas system using measured carbon content and molecular weight of the gas and Equation 30-1.

$$CO_2 = \sum_{i=1}^{n} Fuel_i \times CC_i \times \frac{MW}{MVC} \times 3.664 \times 0.001 \qquad \textbf{Equation 30-1}$$

Where:

CO_2	=	Carbon dioxide emissions, tonnes/year.
$Fuel_i$	=	Daily refinery fuel or flexigas combusted (Rm^3) at reference temperature and pressure conditions as used by the facility. If a mass flow meter is used, measure the daily fuel combusted in kg and replace the term "MW/MVC" with "1".
CC_i	=	Daily sample of carbon content of the fuel (kg C/kg fuel).
MW	=	Daily sample of molecular weight of fuel (kg/kg-mole).
MVC	=	Molar volume conversion factor at the same reference conditions as the above $Fuel_i$ (Rm3/kg-mole).
	=	8.3145 * [273.16 + reference temperature in °C] / [reference pressure in kilopascal].
3.664	=	Ratio of molecular weights, carbon dioxide to carbon.
0.001	=	Conversion factor for kg to tonnes.
n	=	Number of days in a year.

(3) For associated gas, low heat content gas, or other fossil fuels; follow the requirements for general stationary source combustion sources in ON .23(b) or (c), as appropriate for each fuel.

(4) Where individual fuels are mixed prior to combustion, the person may choose to calculate CO_2 emissions for each fuel prior to mixing instead of using the methods in paragraphs (a)(1) or (a)(2) of this section. In this case, the person must determine the fuel flow rate and appropriate fuel specific parameters (e.g. carbon content, HHV) of each fuel stream prior to mixing, calculate CO_2 emissions for each fuel stream, and sum the emissions of the individual fuel streams to determine total CO_2 emissions from the mixture. CO_2 emissions for each fuel stream must be estimated using the following methods:

 (i) For natural gas and associated gas, use the appropriate methodology specified in section ON.23(b) or (c).

 (ii) For refinery fuel gas, flexigas, and low heat content gas, use the methodology in paragraph (a)(2) of this section.

(b) Calculation of CH_4 and N_2O Emissions. The person shall use the methods specified in section ON.24 to calculate the annual CH_4 and N_2O emissions.

ON.34   Sampling, Analysis, and Measurement Requirements

(a) Measure the fuel consumption rate daily using methods specified in ON.25(b).

(b) Daily sampling and analysis to determine the carbon content and molecular weight of the fuel is required if there is sampling at a frequency of daily or more currently or if there is online instruments in place to monitor carbon content.. Otherwise, weekly sampling and analysis of carbon content and molecular weight shall be performed. The equipment necessary to perform daily sampling and analysis of carbon content and molecular weight for refinery fuel gas must be installed no later than January 1, 2012

(c) Measure the carbon content for fuel gas and flexigas using either ASTM D1945 or ASTM D1946. Where these methods do not adequately quantify all major hydrocarbons, then the person may request use of an alternative ASTM or other method to be approved in writing by the Director. . Alternatively, the results of chromatographic analysis of the fuel gas may be used, provided that the gas chromatograph is operated, maintained, and calibrated according to the manufacturer's instructions; and the methods used for operation, maintenance, and calibration of the gas chromatograph are documented in a plan.

ON.35   Procedures for Estimating Missing Data

The person is required to retain a complete record of all measured parameters used in the GHG emissions calculations. Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter shall be used in the calculations by following the requirements of ON.26.

ON.220   Soda Ash Manufacturing

ON.221   Source Definition

A soda ash manufacturing facility is any facility with a manufacturing line that produces soda ash by one of the following methods:

(a) Calcining trona.

(b) Calcining sodium sesquicarbonate.

(c) Using a liquid alkaline feedstock process that directly produces CO_2.

In the context of the soda ash manufacturing sector, "calcining" means the thermal/chemical conversion of the bicarbonate fraction of the feedstock to sodium carbonate.

ON.222   Greenhouse Gas Reporting Requirements

For the purpose of Section 6 of the Regulation the annual emissions data report for soda ash manufacturing shall include the following information at the facility level calculated in accordance with this method:

(a) CO_2 process emissions from soda ash manufacturing line (tonnes).

(b) CO_2 combustion emissions from each soda ash manufacturing line (tonnes).

(c) CH_4 and N_2O combustion emissions from each soda ash manufacturing line (tonnes). Calculate and report these emissions under ON.20 by following the requirements of ON.20.

(d) Emissions of CO_2, CH_4, and N_2O from stationary combustion units not covered by this method shall follow the requirements of ON.20 (tonnes).

ON.223   Calculation of GHG Emissions

Quantify emissions in accordance with EPA 40 CFR part 98.293.

ON.224   Sampling, Analysis, and Measurement Requirements

Sampling, analysis and measurement requirements for this source shall be done in accordance with U.S. EPA 40 CFR 98 Subpart CC Section 98.294.

ON.225   Procedures for Estimating Missing Data

Missing data requirements for this source shall be estimated in accordance with U.S. EPA 40 CFR 98 Subpart CC Section 98.295.

For Steel Manufacturing, the person shall use the method set out in Appendix 14 ON.150 Iron and Steel Manufacturing

ON.240   Zinc Production

ON.241   Source Definition

The zinc production source includes three primary production processes used to produce zinc (i.e., electro-thermic distillation, pyrometallurgical, and electrolytic). In addition, secondary zinc production is also included in this source.

ON.242   Greenhouse Gas Reporting Requirements

For the purpose of Section 6 of the Regulation the annual emissions data report for zinc production shall include the following information at the facility level calculated in accordance with this method:

(a) Annual emissions of CO_2 at the facility level (tonnes).

(b) Annual quantities of each carbon-containing input material used (tonnes).

(c) Carbon content of each carbon-containing input material used (tonnes C/tonne reducing agent).

(d) Inferred waste-based carbon-containing material emission factor (if waste-based reducing agent quantification method used)

(e) If missing data procedures in ON.245(b) is used, report how the monthly mass of carbon-containing materials with missing data was determined and the number of months the missing data procedures were used.

(f) Emissions of CO_2, CH_4, and N_2O from stationary combustion units not covered by this method shall follow the requirements of ON.20 (tonnes).

ON.243   Calculation of CO_2 Emissions

Calculate total CO_2 emissions as specified under paragraph (a) or (b) of this section.

(a) Determine facility CO_2 emissions using continuous emissions monitoring systems (CEMS) as specified in ON.23(d).

(b) Calculate total CO_2 emissions using Equation 240-1. Specific materials that contribute less than 1 per cent of the total carbon into the process do not have to be included in the calculation using Equation 240-1.

$$E_{CO_2} = \sum_i (Q_i \times C_i) \times 3.664$$

Equation 240-1

Where:

E_{CO2} = Annual CO_2 emissions from carbon-containing materials (tonnes);
Q_i = Annual quantity of carbon-containing material i (tonnes);
C_i = Carbon content of carbon-containing material i (tonnes C/tonne process input);
3.664 = Stoichiometric conversion factor from C to CO_2.

ON.244   Sampling, Analysis, and Measurement Requirements

The annual mass of each solid carbon-containing input material consumed shall be determined using facility instruments, procedures, or records used for accounting purposes, including either direct measurement of the quantity of the material consumed or by calculations using process operating information.

The average carbon content of each material consumed shall be determined as specified under paragraph (a) or (b) of this section.

(a) Obtain carbon content by collecting and analyzing at least three representative samples of the material each year using one of the following methods:

   (1) For zinc-bearing materials, use ASTM E1941 - Standard Test Method for Determination of Carbon in Refractory and Reactive Metals and Their Alloys.

   (2) For carbonaceous reducing agents and carbon electrodes, use ASTM D5373 - Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal.

   (3) For flux materials (i.e., limestone or dolomite), use ASTM C25 - Standard Test Methods for Chemical Analysis of Limestone, Quicklime, and Hydrated Lime.

   (4) For waste-based carbon-containing material, determine carbon content by operating the smelting furnace both with and without the waste-reducing agents while keeping the composition of other material introduced constant.

        (i) To ensure representativeness of waste-based reducing agent variability, the specific testing plan (e.g. number of test runs, other process variables to keep constant, timing of runs) for these trials must be approved in writing by the Director.

(b) Obtain carbon content from material vendor or supplier.

ON.245   Procedures for Estimating Missing Data

For the carbon input procedure in ON.243, The person is required to retain a complete record of all measured parameters used in the GHG emissions calculations. Therefore, (e.g., raw materials carbon content values, etc.). Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter shall be used in the calculations as specified in paragraphs (a) and (b) of this section. The person must document and keep records of the procedures used for all such estimates as required by the Regulation.

(a) For missing records of the carbon content of inputs for facilities that estimate emissions using the carbon input procedure in ON.243; 100 per cent data availability is required. The person must repeat the test for average carbon contents of inputs according to the procedures in ON.245(b) if data is missing.

(b) For missing records of the annual mass of carbon-containing inputs using the carbon input procedure in ON.243, the substitute data value must be based on the best available estimate of the mass of the input material from all available process data or information used for accounting purposes, such as purchase records.